THE 1970 NATIONAL POWER SURVEY

[FEDE]RAL POWER COMMISSION

PART IV

GUIDELINES FOR GROWTH OF THE ELECTRIC POWER INDUSTRY

[TH]E ELECTRIC POWER INDUSTRY • STRUCTURE OF ELECTRIC POWER INDUSTRY • THE PROJECTED GROWTH IN THE USE OF ELECTRIC POWER • FUELS AND FUEL TRANSPORT • FOSSIL-FIRED STEAM-ELECTRIC GENERATION • NUCLEAR POWER • HYDROELECTRIC AND PUMPED STORAGE POWER • GAS TURBINES, DIESELS, AND TOTAL ENERGY SYSTEMS • OTHER FORMS OF GENERATION • COOLING WATER NEEDS AND SUPPLIES • AIR POLLUTION • ESTHETICS AND ENVIRONMENTAL EFFECTS • TRANSMISSION AND INTERCONNECTION • DISTRIBUTION SYSTEMS • UTILITY PRACTICES AFFECTING RELIABILITY OF SUPPLY • PROBLEMS IN TIMELY PLANNING AND CONSTRUCTION OF NEW FACILITIES • COORDINATION • POSSIBLE PATTERNS OF GENERATION AND TRANSMISSION FOR 1990 • ECONOMIC PROJECTIONS • FINANCING THE GROWTH OF THE ELECTRIC POWER INDUSTRY • REGULATION OF THE ELECTRIC POWER INDUSTRY • RESEARCH AND INVESTIGATION REQUIREMENTS

THE 1970 NATIONAL POWER SURVEY

FEDERAL POWER COMMISSION

PART IV

TECHNICAL ADVISORY COMMITTEE REPORTS TO THE FEDERAL POWER COMMISSION

PREPARED BY

THE GENERATION TECHNICAL ADVISORY COMMITTEE

THE TRANSMISSION TECHNICAL ADVISORY COMMITTEE

THE DISTRIBUTION TECHNICAL ADVISORY COMMITTEE

THE TECHNICAL ADVISORY COMMITTEE ON LOAD FORECASTING METHODOLOGY

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FOREWORD

In April 1968, the Federal Power Commission established Technical Advisory Committees on the Generation, Transmission and Distribution of Electric Power and the Methodology of Load Forecasting to assist the Commission in updating the National Power Survey. The four Committees were requested to examine the states of the arts, needs and probable future developments, costs and economic factors, and research requirements from the present to 1990.

The Committees reports to the Commission are being published to make the extensive analyses and related information available to all interested parties. The documents are planned to be useful to the nontechnical as well as the technical reader.

As in all Commission Advisory Committee activities, the Commission's staff has participated in the deliberations of the Committees. While consultation and suggestions have been freely exchanged by the Committees and staff, the final reports are the products of the Committees.

We gratefully acknowledge the participation of the members of the Technical Advisory Committees and the many others who assisted them in these studies. Memberships of the individual Technical Advisory Committees are shown in the corresponding report sections of this volume.

THE FEDERAL POWER COMMISSION

PART IV

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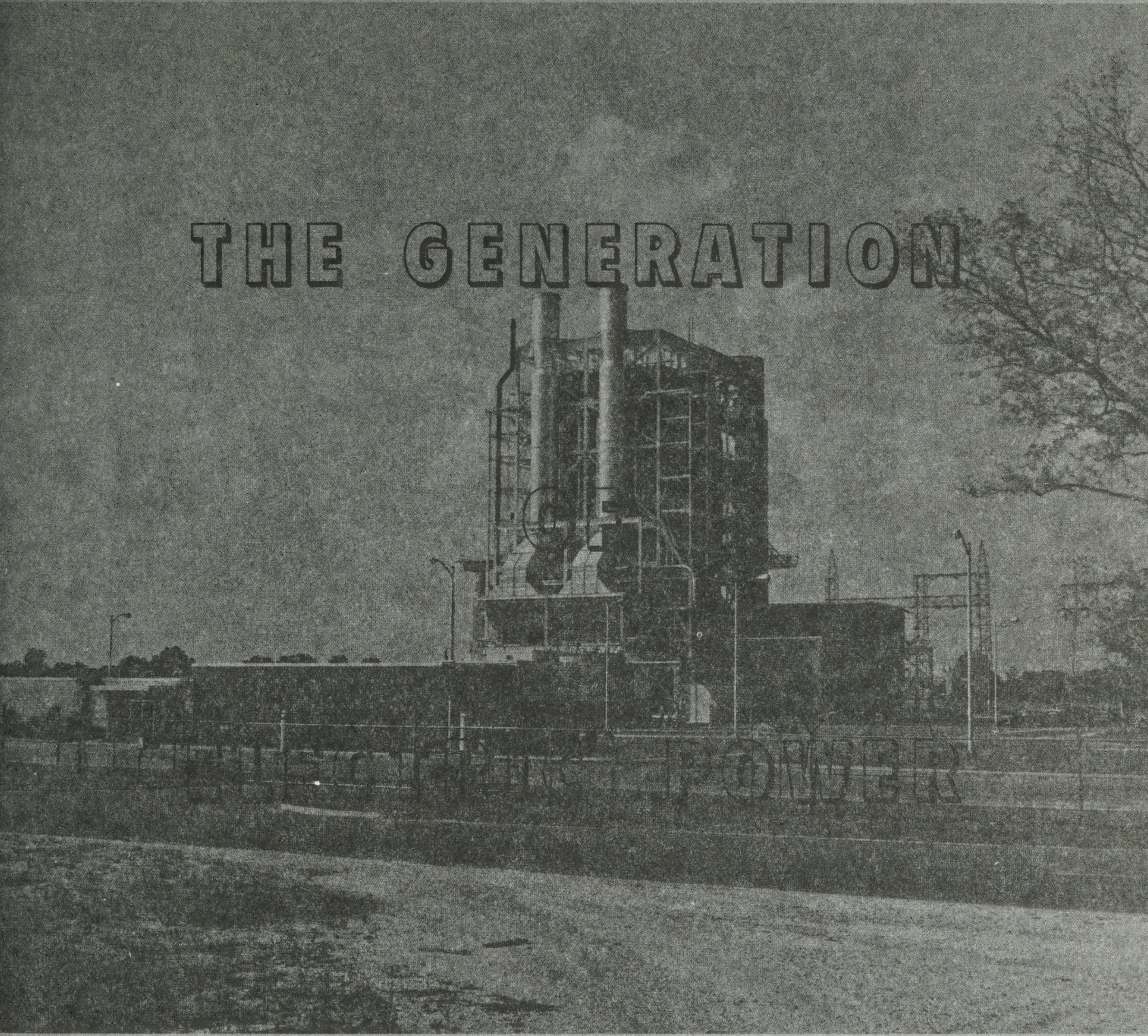
A REPORT TO THE FEDERAL POWER COMMISSION



THE GENERATION OF ELECTRIC POWER

PREPARED BY

THE GENERATION TECHNICAL ADVISORY COMMITTEE

FOR THE NATIONAL POWER SURVEY

AUGUST 1971

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IV-1-xii Add:

The members of the Generation Technical Advisory Committee are:

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Robert E. Peck, Basin Electric Power Cooperative

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INTRODUCTION

The insatiable appetite of the Nation for electric energy provides a challenge that the utility industry has met successfully and is continuing to meet. In anticipating future needs for electric power, the industry is looking forward eight to ten years on a "current planning" basis and twenty years ahead on a more general basis.

Anticipation of requirements in such time references provides an opportunity to assist in advancing the art of electric energy production and to assure that the generating equipment will be available in size, quantity, and types, together with the necessary fuels and plant sites to continue to produce economical and reliable electric power.

The major emphasis in the past decade, insofar as generation equipment is concerned, has been on increasing unit size to achieve lower costs. Increases in plant size have, however, intensified siting and transmission problems. Environmental considerations are adding significantly to the cost of producing power and present indications are that such cost increases will continue, probably at an accelerated rate.

Fossil fuel fired electric plants continue to be basically important in supplying electric energy. In 1962, a 700 megawatt unit was in commercial operation, and in 1965 the maximum size unit in commercial operation was a 1,000 megawatt unit. A 1,300 megawatt unit is scheduled for operation in 1972, and larger size units may reach two or even three times this size by 1990. During this period, economies have resulted from innovations in coal handling, burner control, steam generator design, and generator cooling.

The utility industry is giving great attention to environmental problems which may be associated with air and water quality control, increased sizes of units, changes in types of generating plants, and increased sizes and numbers of generating plants. Research to produce acceptable solutions to all of these problems is being intensively pursued.

Careful attention is being given to removal and dispersion of particulate matter and other products of the combustion process. The establishment of air pollution control standards has been a major factor in focusing attention on low sulphur fuels and the removal of sulphur from stack gases. Increasingly, attention is being given to the use of low sulphur fuels, both coal and oil, and low sulphur coal is being shipped over one thousand miles from Montana to the Mid-west. It may be expected that the low sulphur coals in the Rocky Mountain and the Southwest Mountain States for use in fossil fired plants will be more intensely exploited by economical mining methods.

Cooling water problems, particularly as related to the impact of waste heat rejected from both fossil fueled and nuclear power plants on natural streams and bodies of water, are receiving careful attention. At present the wet cooling tower, or in special cases a cooling pond, seems to offer the only practical method of withholding heat from natural water bodies. However, by 1980 increasing needs to conserve water could result in development and use of some form of dry-type cooling tower or heat dissipating or utilization device.

During the past few years the nuclear power reactor industry has experienced a phenomenal growth. This has resulted from the improved economic position with respect to other means of power generation which nuclear units have gained through improved technology and size increase. In many areas of the country power can be produced at lower cost by nuclear plants than by fossil plants. Despite some temporary setbacks and some decline in ordering in the late 1960's, nuclear units have obviously become an economic choice for many utilities, and the long-term growth outlook for nuclear power is bright. The decline in ordering may be attributed to a number of factors including the traditional cyclic buying pattern followed by the utilities in purchasing generating equipment, and increase in cost of nuclear plants resulting from a number of factors including an overloading of the nuclear industry's fabricating capability, escalation and increased labor costs, and a realization that the cost of nuclear plant construction had, in many instances, been seriously underestimated. An additional factor was the realization that the planning and construction time for a

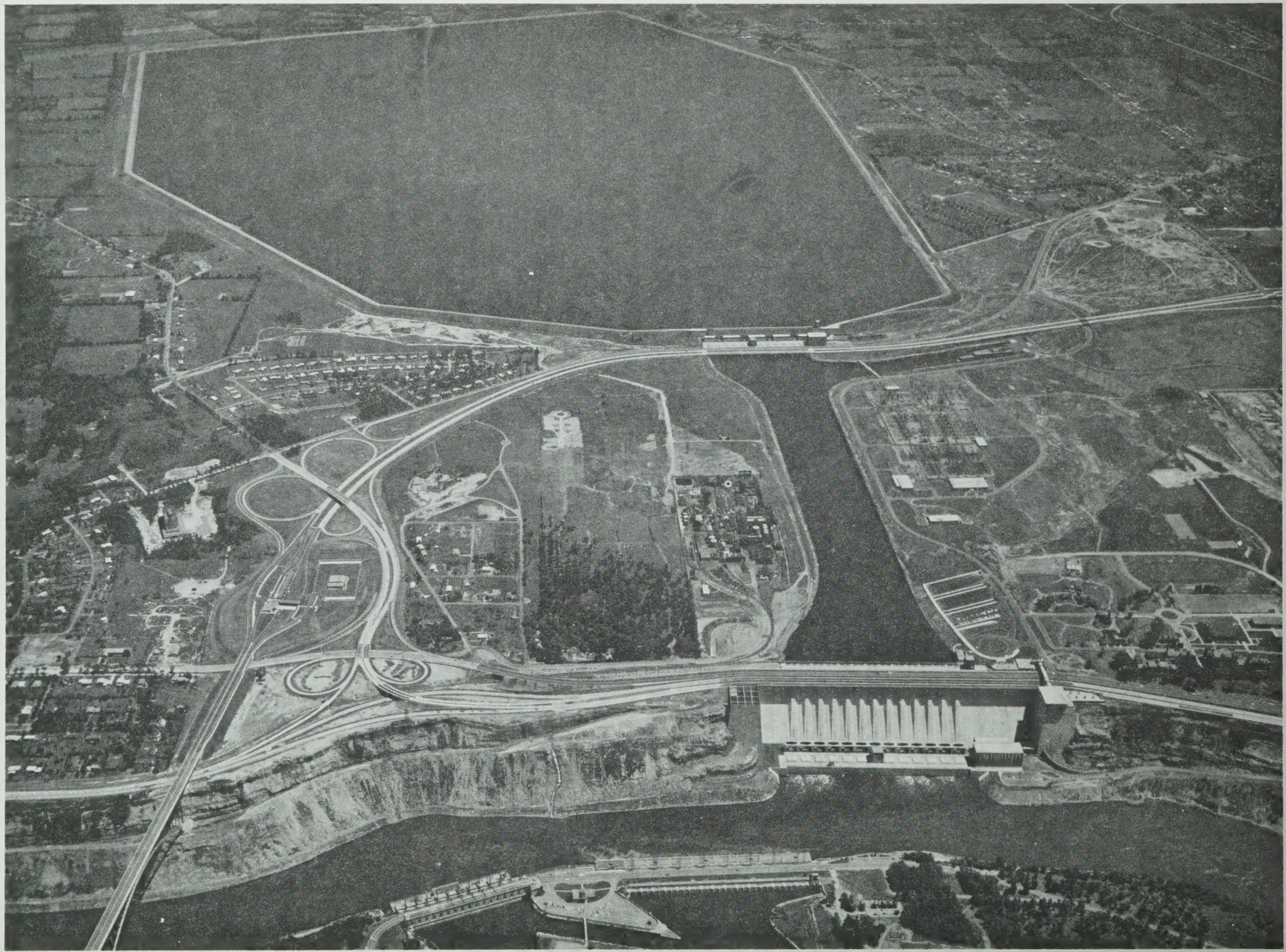


Figure 1.—Power Authority of the State of New York's Robert Moses Niagara Power Plant—1,950 MW in 13 units—(lower right) and its Lewiston Pumped Storage Plant—240 MW in 12 units—(at head of power canal). In foreground is a partial view of Hydro-Electric Power Commission of Ontario's Sir Adam Beck Station containing 1,627.5 MW of conventional hydro capacity and 176.7 MW of pumped storage capacity.

nuclear plant would be in the order of six to seven years or more, approximately one to two years longer than anticipated in earlier plant construction estimates. This extension and the associated uncertainty as to the date of availability of the power plant to produce required power have in some instances resulted in decisions to cancel or defer nuclear plant purchases and substitute fossil-fired plants which can be constructed in from four to five years. Recently, however, orders for nuclear plants have accelerated and the growth rate of nuclear power is expected to return to earlier expectations.

It should be borne in mind that the nuclear power industry is very young and that the large-sized plants now under construction are yet to be tested in actual operation. There are potentials for development which should contribute to cost reduction, including larger size units, standardization of components, improved construction methods, and more efficient manufacture and utilization of fuel for plants of existing and advanced designs. It is also recognized that significant cost reductions can be attained by improved planning and scheduling of construction and regulatory activities. The operating experience which will be gained with the passage of time should be a contributing factor to establishing the nuclear plant industry on a more routine basis and to facilitating acceptance by the public.

Hydroelectric generating plants occupy a unique position in that they complement or supplement base fuel fired energy plants. This important functional relationship has resulted in the construction of pumped storage plants in increasing numbers. The limit on the use of hydroelectric plants will be the natural limit of availability of sites, both for regular and pumped storage plants, and the relative economics of supplying the peaking power by hydroelectric means as compared to fuel fired means. There have been some significant developments in late years in the use of larger physical sizes of turbines for new and redeveloped sites and the use of bulb or tunnel type units to exploit more favorably relatively low hydraulic heads. Advances have been made in the design of reversible generating pumping units but it is not expected that there will be continued significant increases in economies and efficiencies.

Internal combustion engines will continue to have a place in the mix of plants supplying power, particularly for peaking applications. Diesel units of 40,000 kilowatt size are now available in single generator factory assembled packages, and generating units of 100,000 kilowatt capacity are expected to be available by 1990. Improvements in heat rate are not expected to be significant.

The gas turbine generating unit is being used for a source of peaking and emergency power, and packages of units under common control are currently available up to 240,000 kilowatt capacity. This type of turbine has unique characteristics, particularly with respect to quick starting and synchronizing, and thus can qualify as ready reserve capability in many systems. Cooling water or large areas for on-site fuel storage are not required, and therefore such plants may be located close to load centers and in bulk power substations. The use of high quality fuels indicates less potential for environmental pollution.

A number of energy conversion devices have been extensively investigated in recent years in a search for lightweight, long-lived, and reliable power sources for space and special military applications. Some of these have received further consideration with the anticipation that they might prove sufficiently economic to compete with conventional generating equipment in the production of power for general use. The concepts that have received the most serious consideration are magnetohydrodynamics, fuel cells, thermionics, thermoelectrics, and electrogasdynamics.

In addition to the energy conversion devices that would convert chemical energy, kinetic energy, or heat to electricity, controlled thermonuclear fusion offers the possibility of direct conversion of the energy of nuclear fusion to electricity. The feasibility of nuclear fusion has not yet been demonstrated. It is unlikely that nuclear fusion will be a major contributor to power generation in this century unless the pace of development is substantially increased or technical progress of a "breakthrough" nature occurs.

Recently, activity in solar energy has been renewed with two proposals for utilizing it. The methods being considered are a sunlight-algae-methane-steam-power cycle and a sunlight-thermal energy-steam-power cycle. The President's June 1971 energy message to the Congress included solar energy development and some believe that solar energy could become a significant energy source within this century.

Of the energy conversion techniques being considered today, magnetohydrodynamics and fuel cells appear to be the most attractive and perhaps the only ones far enough advanced in the development cycle to be probable competitors in the production of power and then only late in this century.

The foregoing is discussed in detail in the following pages, but it may be generally concluded that unit generating sizes for all methods of generation will be larger, and thermal power plants will be much larger by 1990. Unit costs will be increased by greater use of anti-pollution devices with possible adverse effects on efficiency, and by required selection of sites for reasons other than those most economical from the standpoint of transmission and favorable power loss factors. The utilization of more efficient devices, however, will significantly reduce the quantity of pollutants rejected to the environment.

During the early part of the 1960's, the priority of economics held sway in the development of electric generating facilities. In the middle 60's, more emphasis began to be applied to matters of reliability and in more recent years, environmental effects of power generation have become a paramount consideration. Conservation of resources is currently demanding fuller utilization of the waste produces of the generation cycle, from ashes to heat. These considerations, together with the impact of increasing labor and money rates have today resulted in higher costs of generation. The future increase in power generation capability compatible with the other social needs of the nation will be provided as economically as possible, but not without substantial increases in the cost of electric power to the customers.

Much of the data for this report was collected in 1968 and early 1969. Although an attempt has been made to provide more current information in many parts of the report, it has not been possible to completely update every section. Nevertheless, it is hoped that the report will serve as a useful reference manual for many who are interested in the present status and future development of this area of the electric power industry.

CHAPTER I
FOSSIL-FIRED STEAM-ELECTRIC GENERATION

Summary

The most noteworthy development in recent years in steam-electric generating units has been their increase in size and the accompanying progress in technology that made these increases possible. Along with this increase in unit size from 700 mw units in 1962 to 1,300 mw units scheduled for 1972 have also come increases in plant size. The interest in larger units and plants, of course, stems from the utilities' desires to reduce per unit capital and operating costs. The availability of large blocks of power has had a significant impact on system planning, design, and operation. It is expected that the trend to increasing unit sizes will continue because of the expected per unit decline in cost with increasing size and that by 1990 we could expect to have 3,000 mw units available.

The growth in unit size has not been accompanied by major reductions in unit heat rates, and throttle pressures and temperatures have remained about the same. Some modest improvements in efficiency, however, are expected as units increase in size. Research and development should eventually provide the materials necessary to economically increase steam temperatures above 1,000°F. Most of the future large units will probably be supercritical single reheat units.

It is expected that the trend to automatic control of generating plants will continue since the complexities involved in operating these larger units make computer control almost mandatory. In addition, most, if not all, of the cost should be recovered by the fuel savings resulting from optimum operation of the plant and some possible reduction in operating personnel.

The increase in unit sizes appears to be accompanied by some increase in forced outage rates with boiler outages being the chief cause of the outages. However, the data to date for these units are based on a very short period of time, and it is expected that as these units mature and experience is gained with them, they and the second and third generation units will show substantial improvements. The larger units do have more complex maintenance requirements that result in longer down times. However, the cost per unit of output is still lower than for small units, and it is expected that maintenance problems with larger units will decrease as experience is gained and design improvements are made.

The siting of large blocks of thermal capacity requires careful attention to the problem of rejecting waste heat. The criteria selected by the interested parties must achieve a balance among all the potential needs for the water and should be no more restrictive than absolutely necessary and should be based on sound biological and economic studies.

Air quality control is another problem that becomes more complex with increasing size. It is hoped that research now in progress will lead to practical means of reducing excessive emissions from fossil-fired plants. In the meantime, utilities will utilize higher stacks, electrostatic precipitators, and in some cases low-sulphur fuel among other means to maintain effective control of stack effluents. Even with the use of relatively low sulphur coal, SO_2 removal equipment may be necessary to meet requirements in some states.

Current trends indicate that the price of coal delivered to generating plants will increase. However, in order for the coal industry to retain its competitiveness in the energy market, advancements in mining and transportation techniques must continue, as illustrated by the recent increases of nuclear orders and the declining percentage relationship of orders for fossil-fired capacity. It is anticipated that for the period 1975 to 1980 fossil-fired capacity will make up approximately 50 percent of total capacity additions and will decrease to 40 percent for the period 1980–1990. A potential element in the competitive picture is the trend toward consolidated ownership of all raw thermal energy supplies—coal, petroleum, and uranium.

The ever growing demand for power and the increased sophistication in plant equipment will

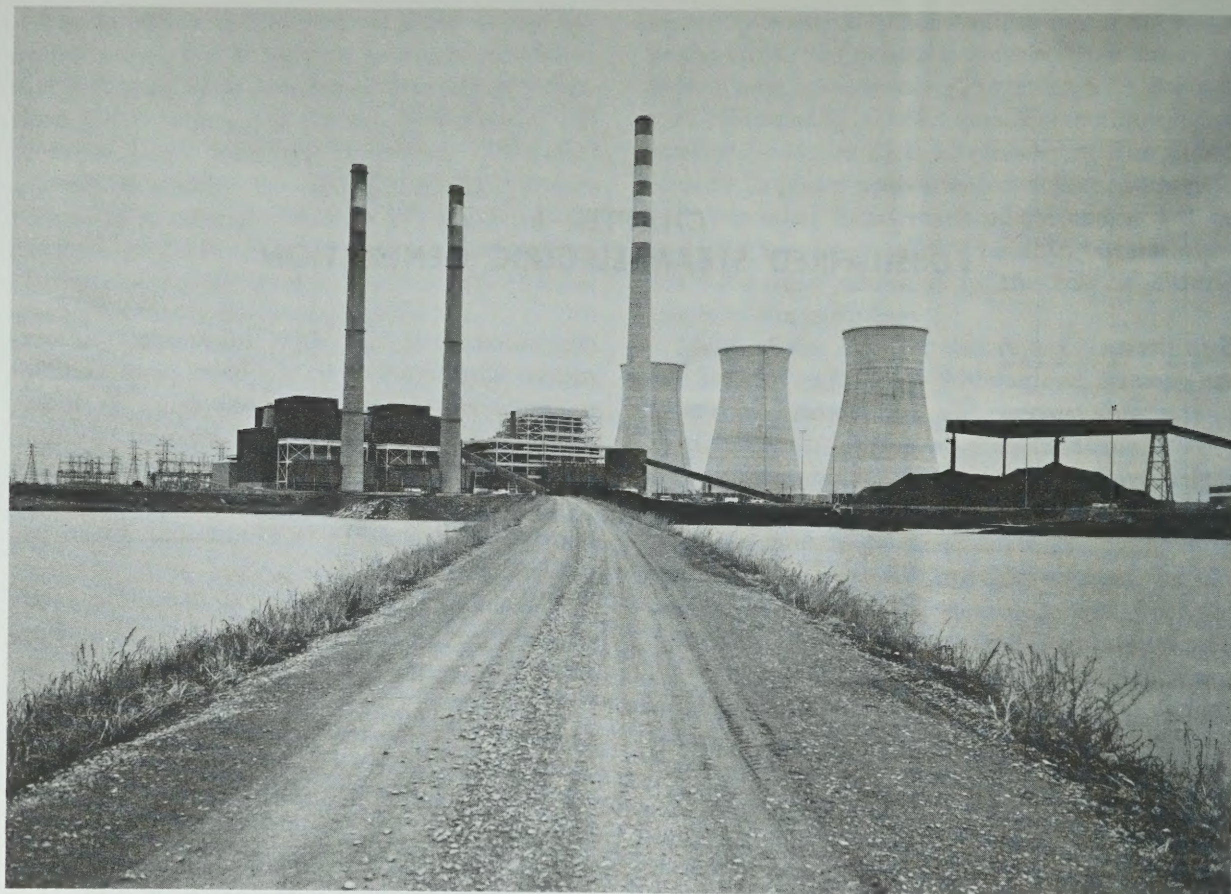


FIGURE 2.—TVA's Paradise Steam Plant, the largest in the country, with a generating capacity of 2,558 megawatts. It contains two 704-megawatt units and one of 1,150 megawatts.

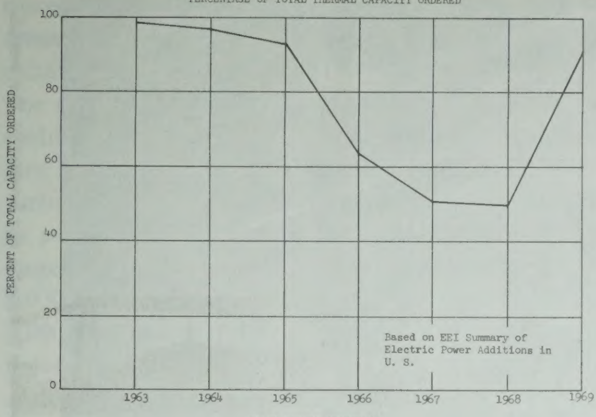
require not only more manpower but personnel with backgrounds of greater technical depth than in the past. The electric utility industry will need to provide stimulus to the university and technical school programs and may have to undertake the equivalent training itself to provide sufficient technically trained personnel.

During recent years significant advances in fossil-fired generation have been announced, including innovations in coal handling, cooling water facilities, water treatment methods, burner control, steam generator design, generator cooling, and in other areas. The major emphasis in the past decade has been on increasing unit size, and the attention drawn to the frequent announcements of ever increasing capacities of units being planned for addition to power systems has overshadowed the progress in technology that was necessary to achieve the increases in size. Major advances in the improvement of cycle efficiency have not accompanied this growth in unit size, and throttle pressures and temperatures have remained on a plateau. Nevertheless, in high fuel cost areas, the gains in efficiency through the use of double reheats have proven to be economical. The rapid growth, not only in the maximum size unit but also in the average capacity of new units scheduled, is a consequence both of the economic advantages of the larger units and of the many new pooling arrangements permitting the use of larger units.

Perhaps one of the most significant occurrences in the recent past has been the large number of orders for nuclear units in the 1966–1968 period and the declining percentage of orders for thermal capacity additions represented by fossil-fired generating capacity. This is shown in Figure 3; however, since fossil capacity generally has shorter lead times than nuclear installations, pressure to meet demands for electric power has resulted in additional orders for fossil units for operation in the 1972–1973 period. Thus, the percentage of nuclear capacity actually installed in a given year will probably not reach 50 percent until sometime after 1975; however, it seems clear that nuclear power has estab-

FIGURE 3

ORDERS FOR FOSSIL-FIRED ADDITIONS AS A PERCENTAGE OF TOTAL THERMAL CAPACITY ORDERED



lished a competitive position in many parts of the country when compared to power produced by other fuels.

It is anticipated that for the period 1975 to 1980 fossil-fired capacity will make up approximately 50 percent of total capacity additions of all types, and for the 1980–1990 interval fossil generation will constitute in the order of 40 percent of additional capacity installed during that period. Thus, in 1990 the total fossil-fired installed capacity will represent about 50 percent of the total installed capacity on U.S. utility systems. Since nuclear units have a greater economy of scale factor than do fossil-fired units, it is expected that nuclear units will represent an even greater percentage of the very large units added than the percentages stated above would indicate. In order for fossil-fired capacity to capture and hold the percentages forecast, much research and development work is required particularly in air quality control (removal and dispersion of particulate matter, noxious gases, and other products of the combustion process).

Trends in Size

During the past decade, the most outstanding trend in steam-electric generating units has been their increases in size. With the increases in size, developments have been made in generator stator cooling, rotor cooling, controlled rectifiers and brushless exciters, turbine blade and exhaust hood design, turbine driven boiler feed pumps and fans, and boiler feed-water treatment systems. Plants, too, have become larger and larger, and their impact on system planning, design, and operation has been considerable.

Sizes of Units

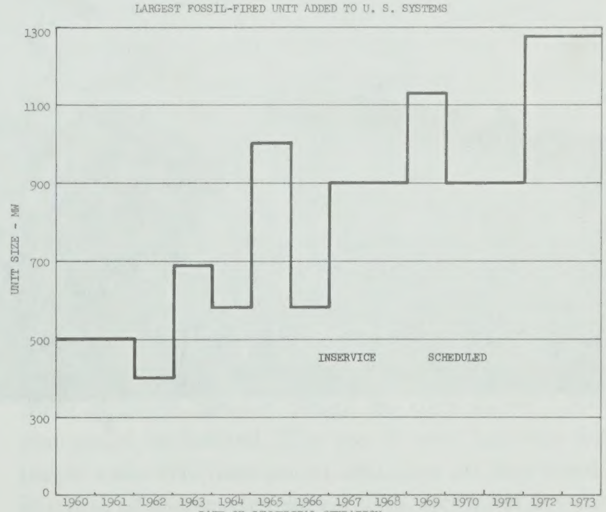
The demand for larger unit size has increased substantially in recent years, as reflected in Figure 4 which shows the maximum size of fossil-fired units placed in service or scheduled for commercial operation from 1960 to 1973. As seen from this curve, the growth in maximum size for recent years has been quite rapid with the maximum unit size almost tripling within the period. The larger utilities and the many power pools now in existence have taken advantage of the savings in the manufacture, erection, operation, and maintenance of larger units. These savings have been made possible through improvements in design, metallurgy, and manufacturing techniques.

The transition of the nuclear industry from the experimental embryonic stage into its present competitive status has been a factor in these advancements. In fact, this transition was brought about, to a large extent, by taking advantage of savings with large size units. This has contributed to the overall advance in electric generating unit size, particularly the tandem compound turbine-generator. Figure 6 shows the unit size distribution of units on order as of October 1968, and predicted distributions for 1975, 1980, and 1990. It is interesting to note that by 1975 it is projected that over half of all capacity added will be larger than 1,000 mw. By 1990 this figure is forecast to grow to 1,800 mw.

The mass flow of steam required for very large units poses some development problems for the turbine designer. Since the steam conditions for large fossil units are not predicted to change drastically from pressures of 3,500–4,000 psia and temperatures of 1,000°–1,050°F., the mass flow

FIGURE 4

LARGEST FOSSIL-FIRED UNIT ADDED TO U. S. SYSTEMS



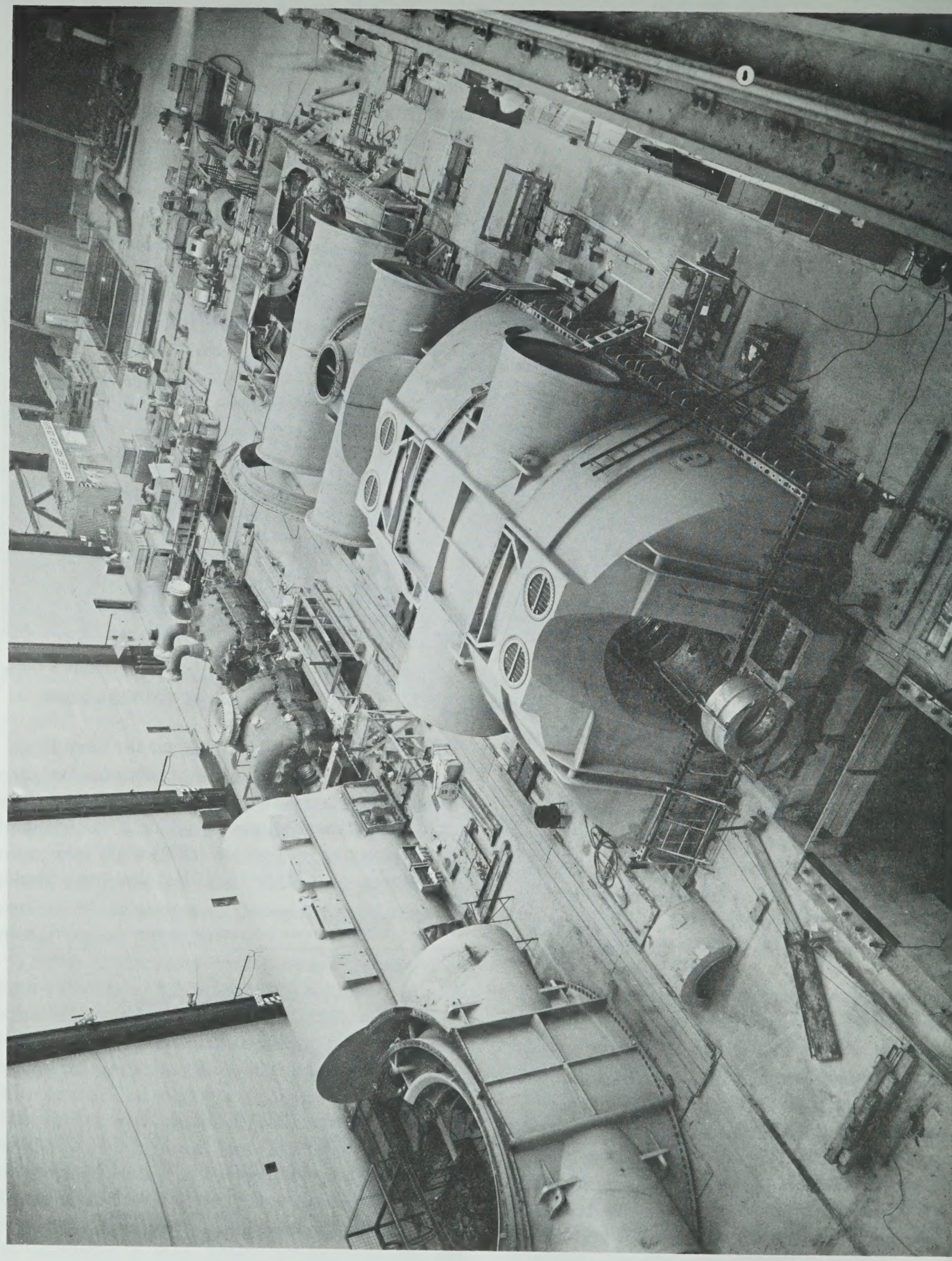


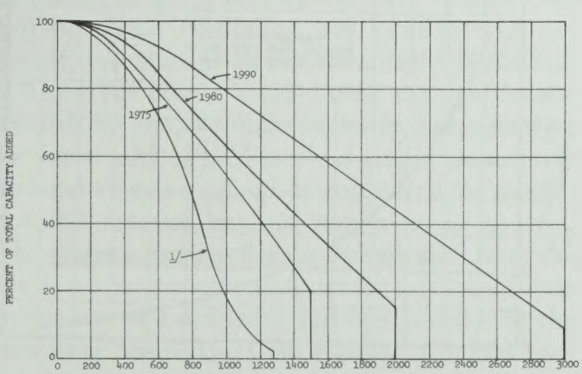
Figure 5.—Turbogenerator for the third unit at TVA's Paradise Steam Plant. This unit rated at 1,150 megawatts is presently the largest in the world.

requirements will increase in proportion to unit size increases. The larger flows, especially those required for the low pressure saturated steam produced in light water nuclear reactors, require increases in cross sectional areas for the inlet and exhaust sections and longer blades for the rotors. For a given stress level an 1,800 rpm low pressure turbine will pass about four times the volumetric flow that a 3,600 rpm turbine will pass. In nuclear turbines the exhaust flow is some 70 percent higher in pounds per kilowatt than in fossil units. Last stage blade lengths of 26 inches to 33½ inches for 3,600 rpm turbines and 38 inches to 43 inches for 1,800 rpm turbines are typical of blade lengths on units being ordered today, and at least four units with 52-inch last stage blades are in operation and several more on order. The large units predicted for the 1970–1990 period will require larger exhaust areas from low pressure turbines. It is expected that turbine manufacturers will develop the materials and techniques to supply the longer blades needed to develop greater exhaust areas.

Generator manufacturers are confident of their ability to design generators to match the demand as the unit size is increased. It is predicted that 1,500 mva, 3,600 rpm, and 2,500 mva, 1,800 rpm generators will be available for shipment by 1975. To reach these and higher levels, larger quantities of heat must be removed from the generator; water cooled stators are now relatively common, and it is expected that water will replace the present hydrogen cooling for rotors and become a standard feature for the large generators of the future. It is predicted that short circuit ratios, a factor which gives a rough approximation of machine stability during disturbances, will continue to decrease but will not go below 0.4 because, with present technology, there is no apparent economic advantage

FIGURE 6

PROJECTION OF UNIT SIZES DISTRIBUTION OF STEAM-TURBINE FOR ADDITIONS TO U. S. GENERATING CAPACITY



in achieving a lower value. Economic consideration must be given to the design and selection of bushings, switchgear, bus sizes, and insulation to handle the increased currents and reactances as generator ratings increase. However, it is not predicted that generator terminal voltage will increase above 30 kv.

Further increases in unit sizes will probably require multipiece forgings for generator rotors; however, the turbine generator manufacturers appear confident that the technology will be available to accomplish this without sacrificing availability or reliability. The availability of 2,000 mw tandem compound units utilizing eight flow exhaust ends for use in fossil-fired plants is expected for in service use by 1980.

In the past, the main incentive to build cross compound units came from the desire to achieve the economies of scale that technology for tandem compound units would not allow. However, with the advances in the design of tandem compound units there is a general trend away from cross compound units, and it is expected that tandem compound units will be the predominant turbine-generator arrangement for the period to 1990 and that cross compound units will generally only be used in instances where tandem compound units are not available in the desired unit sizes.

Problems are encountered in design, manufacture, shipping, and erection that limit the size of a unit. Without improvements in several or all these areas, shipping weight and dimensions would have limiting effects on the allowable physical size. However, the physical size of units is not expected to be the limiting factor for increasing unit size. Through technological advances, the manufacturers have held the maximum stator weight relatively constant. For instance, a 325 mw unit built in 1957–58 had a stator weight of about 540,000 pounds, and heaviest stator weights for a 700 mw cross-compound unit placed in service in 1962 and a 950 mw cross-compound unit placed in service in 1965 were still within the same range.

The development of steam generators has kept pace with the increase in sizes of turbogenerators. Many limitations in boiler design have been overcome, and there will be more to be overcome as unit sizes increase. Structural integrity of a single furnace enclosure may present a major design problem in the larger size units, and the future development of single furnace design for sizes above 1,500 mw could be limited. The use of twin furnaces for larger units will increase as unit sizes are increased. Because of stresses developed with increased fan tip

speed, induced draft and forced draft fans are approaching a limit in size with today's technology; however, this obstacle can be overcome by increasing the number of fans per unit. The maximum practical length for soot blowers appears to be about 65 feet, and research and development will be necessary to overcome this handicap in the design of large coal-fired furnaces.

A considerable effort is being expended not only in the United States but in other countries as well on research and development of fluidized bed combustion. Fluidized bed combustion can be briefly described as burning relatively small particles of crushed coal suspended by combustion air introduced through a perforated base plate. The upward air flow agitates and partly levitates the coal and ash. Very attractive gas-side film coefficients and high heat release rates are attainable if the heat transfer surface is immersed in the turbulent fluid bed. Liquid and gaseous fuels as well can be burned in a fluidized bed of noncombustible refractory particles. Average bed temperatures are below that of ash fusion and range from about 1,400° to 1,900°F. It is postulated that nitrogen oxide formation should be inhibited at this lower temperature. In addition, this temperature range appears ideal for the reaction of gaseous SO_2 and SO_3 formed with limestone added to the fluid bed to form calcium sulfate which can be removed with the ash. Thus, the fluidized bed combustion boiler may make possible a more compact and lower capital cost steam generator with reduced nitrogen oxide emission potential and which permits simple control of SO_2 emissions without expensive additional equipment.

It is the confident opinion of those associated with the design and manufacture of power generating equipment and of those in the utility industry who are concerned with producing electricity that advancing technology will provide the know-how to allow the continued increase of unit sizes to satisfy future demands.

Economic Aspects of Sizes

The demand for the increases in unit sizes has been created by the desire of the utilities to reduce the unit capital costs of new generating capacity and to effect savings in operation and maintenance costs over the life of the unit. As shown in Figure 7 the capital cost incentive can be quite substantial. For instance, in doubling the unit capability some 10–15 percent of the initial \$/kw investment cost can be saved. However, selection of the size of a new unit is determined by the size and characteristics of the utility system as well, since reliability and other considerations also influence the economics of system operation.

The advantage in operating and maintenance costs for larger units is also quite significant. These are mostly savings in operating costs (excluding fuel) and occur primarily from the fewer number of operating personnel required on a per kw basis. Figure 8 indicates the relative number of employees required for each 100 mw of installed capacity for a two-unit coal-fired plant with unit sizes varying from 300 mw to 1,500 mw.

Through advances in technology, including the economies of scale with larger generating units, utilities can combat rising equipment and labor costs.

Load Changing Ability of Units Versus Size

Some problems have been encountered in using large units to meet large load swings. Turbine thermal stresses and rotor casing differential expansion are major factors limiting rapid starting and loading and dictate means of closely matching steam and turbine metal temperatures. The lack of flexibility in some auxiliaries to follow load swings also limits rapid loading of large units. However, after units reach normal load, they will respond to load changes with the same percentage swings as much smaller units. In tests, load swings of three percent per minute have been made on 500 and 900 mw units. However, some difficulty has been experienced in trying to operate large units at the same relative low load levels as smaller units are able to operate. This is caused by a number of factors: an inadequate control system, inadequate instrumentation, lack of equipment flexibility, and furnace instability, etc.

FIGURE 7

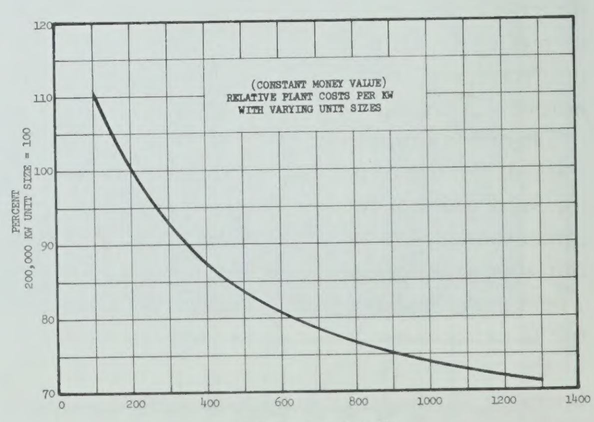
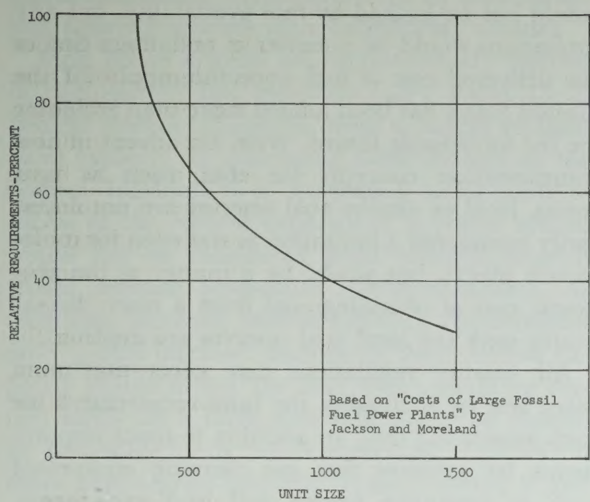


FIGURE 8

RELATIVE NUMBER OF OPERATING AND MAINTENANCE PERSONNEL
PER 100 MW FOR A TWO-UNIT PLANT



Unit Auxiliaries

Progress in condenser design and development during the past decade has kept pace with the increase in size of the units. During this same period of time there has been an increase in public awareness of the potential problems of thermal stream pollution and in guidelines and directives established at both state and national level to establish guidelines for water temperatures. This has resulted in increases in design efforts to obtain cooler water for the condenser intake and to use special methods for discharging the heated water in a suitable manner to maintain satisfactory water temperatures. In most cases, the heat discharged to the receiving waters is dissipated to the atmosphere, and thermal criteria on surface waters should, but often do not, recognize the limited surface area of waters affected before the heat is absorbed into the atmosphere. Thus, the condenser design and the disposition of the heat temporarily through receiving waters or directly to the atmosphere through cooling towers or cooling ponds is dictated by water quality control standards, economics, site location, and the nature and amount of water available at the site.

There has been a trend during the past decade towards the use of turbine boiler feed pump drives for fossil units of medium and larger sizes. Some direct shaft drives have been employed for pumps, but this practice has not caught on in general. There seems to have been a distinct shift from the use of extraction-type turbines for auxiliary drives to the use of condensing turbines because of the operating flexibility at the expense of initial cost. The use of a motor-driven start-up pump in conjunction with turbine-driven pumps is gradually decreasing, and the use of auxiliary boilers to provide steam during starting of the main unit is increasing. The future trend will be to more turbine drives as unit sizes continue to increase and for more turbine-drive applications, such as forced-draft fan drives, soot-blowing air compressors, etc.

Although the trend has generally been to more efficient auxiliaries of all kinds, a leveling off in pump design efficiencies can probably be expected. This would result from the desire to obtain more reliable equipment, at the expense of efficiency, by increasing the internal clearances. The present trend of increasing the head per stage will continue as operational data are accumulated.

Quality Control and Assurances

The failure of a large unit and the resultant higher cost of replacement power or possibly the loss of load is much more expensive to a utility than a failure of a small unit. For the same reason, a delay in construction is much more expensive with a larger unit. For this reason increased emphasis is being given to stringent quality control programs in system and component design, fabrication, and assembly of units. Most utilities have also instituted more comprehensive quality control programs in plant design, construction, and startup of units. The chief objectives of the quality control and assurance programs are to minimize problems which lead to these costly construction delays and to assure safe and reliable plant operation.

Factors Affecting Maximum Plant Size

The economic advantage of size which is realized in the installation and operation of large steam units can also be taken advantage of in the construction of large, multi-unit plants. The main areas of economic improvement are in the capital costs per kilowatt and the operating and maintenance costs (excluding fuel) per kwh. The costs of the portions of a plant that are needed regardless of the number of units, such as the office space, shops, storerooms, landscaping, docks, etc. can be spread over more capacity, thus reducing the dollars per kw cost. Similar savings can be realized in other areas of the plant such as coal unloading, processing, and handling facilities. If cooling towers or a cooling pond are needed to provide supplementary cooling, the cost per kw can usually be reduced if the installation is planned for a plant of two or more units.

The development of industrial and recreation sites along the banks of our rivers and on the shores of our lakes and oceans has led to an intense competition for the use of sites best suited for power plants. To make the most of the sites that are available, increases in unit sizes and the use of extra high voltage transmission have made it possible to install greater amounts of capacity at single locations. However, in developing larger plants it must be realized that land requirements for some of the facilities will increase in proportion to the plant size. These include coal storage areas, ash disposal areas, and possibly installations needed to dissipate the heat rejected from the turbine condenser, such as cooling towers or cooling ponds. Air cleanup systems and future installations of sulfur dioxide removal systems will require additional land.

One of the most difficult problems to be solved in the development of large plants is to obtain an economic source of condenser cooling water. The most economical arrangement is a once-through system utilizing water from a river, lake, or ocean. However, circulating water requirements are quite large for a large plant utilizing a once-through system. Also, governmental regulations now in force, or being proposed, limit the amount of heat that can be discharged to a natural water source to the point where there will be few sites on which a large power plant can be built without some means of controlling the heat rejected to the water source. Various modifications to the conventional once-through system which may be used to maintain the desired water quality standards are described in "Cooling Water Requirements."

Cooling towers may be used in areas where there is insufficient water for a once-through cooling system and where the construction of a cooling pond is uneconomic or not possible. The use of cooling towers will probably increase in the future as the limited number of riverfront and shorefront sites are employed for power plants and industrial sites. The use of cooling towers may substantially increase the electrical capacity that can be installed on a site, providing makeup water requirements can be met. However, cooling towers increase the amount of land required and add to the plant investment and operating and maintenance costs over the life of the units.

It is conceivable that the problem relative to heated wastes could change from one of thermal pollution to consumptive use and environmental changes resulting from the discharging of large quantities of heated waste into the atmosphere from cooling towers.

In the foreseeable future, the size of a plant would not be limited by fuel availability, but any limitations would be a matter of economics tied to the delivered cost of fuel since the supply for the United States has been judged more than adequate for the foreseeable future. With the advent of new transportation concepts for coal, such as unit trains, local or nearby coal reserves are not necessarily considered a limitation to size even for mine-mouth plants, but would be a matter of the economic cost of obtaining coal from a more distant source once the local coal reserves are depleted.

Air quality regulations can affect maximum plant size by increasing the land requirement for each generating unit. In addition to space requirements for primary flue gas cleaning equipment such as scrubbing towers and heat exchangers, some processes require additional area for such supporting structures as settling ponds. Aside from the economics, there may be a practical limit to the amount of flue gas that can be handled effectively by the pollution control equipment. At the present time, no proven method has been developed for effectively removing sulfur dioxide from flue gas at a reasonable cost. Knowing this, some regulatory bodies are requesting that space be left when designing new power plants to permit installing such equipment at a later time. It is assumed that it will only be a matter of time before technological advances make such equipment available. In the meantime, some power plants stock a short-term supply of special low-sulfur coal for use in periods of atmospheric stagnation. However, some air pollution codes would require continuous use of low sulfur coals or removal of sulfur. Maximum permissible sulfur content is already set at 0.5 percent or less in some areas. (See "Air Quality Control".)

The current legislation and directives for air quality control are lacking in uniformity, with respect to the various offending industries. Some proposed regulations are apparently beyond the capacity of present control apparatus and in some cases could limit the size of plants allowed. These restrictions can have an extremely adverse effect on the economies of large generating units and stations.

System Limitations

There are several factors related to power system operation which limit the maximum size of a unit

or a plant that can be installed on a power system. The amount of annual load growth could be a limitation, which may be overcome by interchange and sales agreements with neighboring utilities.

Most power systems are predominantly thermal in composition and generally carry about 15–25 percent reserve capacity in order to supply replacement capacity for generating plant outages on the system. Installation of generating units sized in excess of the reserve capacity of a power system would not be considered good practice since it would seriously jeopardize system reliability. As unit sizes increase, reserve capacity requirements on a system increase. Because of these reserve capacity requirements, the load which could be carried safely on a large new unit might be limited by reliability needs rather than unit capability if there were a great disparity in size between it and other units on the system.

Additional reserve capacity may also be required as a result of a large plant as compared to several smaller plants. In order to gain the economics of large size units and plants, some power systems have minimized the additional reserve requirements by pooling agreements and joint ownership of power plants with neighboring utilities.

Electric systems are becoming larger, not only through growth, but also through consolidation. In the past 20 years, the number of investor-owned utilities has been reduced from 320 to less than 210. This trend will undoubtedly continue. In addition to system mergers, the trend to power pooling will also accelerate. Some of the loose power pools will become stronger with a central organization responsible for planning and constructing and operating power facilities. The large size resulting from such consolidations and pools increases their ability to accept larger generating plants and units. Therefore, these large systems will be able to accept larger units and plants as they become available.

The problem of unit and system stability is also a very important factor in the consideration of adding larger units. In general, the larger the unit at a given speed (3,600 rpm or 1,800 rpm), the larger is the ratio of kilowatt output to the weight of the rotating parts, and the lower the WR^2 [1] per kw of rating. This lower unit WR^2 results in a machine which has a lower inherent stability during major system disturbances. If a system is designed with a specific stability criterion, more investment in transmission facilities may be required to maintain an acceptable stability level if very large units are installed. However, some advanced techniques might be applied to very large units to increase their response during disturbances. These techniques could include such items as dynamic braking, fast valving, load insertion, and high response and high speed supplemental excitation schemes.

The geographical and electrical distribution of existing loads, projected load growth, and the characteristics of other generating capacity on a system affect the maximum plant and unit size which will be economical for that particular system. These factors relate primarily to the economics of providing transmission facilities required to connect adequately the plant or unit into the system as a reliable power source.

It is imperative that system conditions such as capacity reserve requirements, stability considerations, and transmission requirements be included in the economic analysis of adding larger generating plants and units to a system or to a group of coordinated systems.

Unit Performance Trends

A characteristic of United States utilities is the constant striving to produce electric energy at the lowest possible cost while maintaining the world's highest degree of system reliability. This desire by utilities has resulted in the efficiency of thermal generation being constantly improved. Table I–1 shows the net plant heat rates for the 23-year period ending with 1969 for the most efficient plant in the United States, the most efficient system, and the average heat rate for all steam-electric generating plants in the United States. It is interesting to note from this table that the average kwh generated in 1968 (the lowest record year) required 5,200 Btu less than did an average kwh in 1947. If this is combined with a fuel cost of 25 cents per million Btu, it results in the resounding savings of 1.3 mills per kwh. In order to achieve these efficiency improvements, utilities have installed equipment using steam at higher pressures and temperatures incorporated into optimized cycles using one and, in some cases, two stages of reheat. In 1969, the best heat rates were a little higher than the values reported for 1968. This trend was attributed primarily to decreasing quality of the coal used to fuel many power plants.

[1] A constant, used to describe inertia of rotating machines, where W is the rotating weight in pounds and R is the radius of gyration in feet.

TABLE I–1

Net Heat Rates for Steam-Electric Generating Stations

Year	Best plant Btu/Kwh	Best system Btu/Kwh	U.S. average Btu/Kwh
1947	10,600	NA	15,600
1948	10,588	NA	15,738
1949	10,437	NA	15,033
1950	9,378	11,876	14,030
1951	9,379	11,676	13,641
1952	9,303	11,665	13,361
1953	9,329	11,185	12,889
1954	9,113	10,362	12,180
1955	9,151	10,062	11,699
1956	9,106	9,780	11,456
1957	9,118	9,705	11,365
1958	9,130	9,760	11,085
1959	9,011	9,620	10,970
1960	8,975	9,590	10,760
1961	8,760	9,363	10,650
1962	8,588	9,390	10,558
1963	8,714	9,364	10,482
1964	8,776	9,478	10,462
1965	8,717	9,404	10,453
1966	8,691	9,460	10,415
1967	8,682	9,487	10,432
1968	8,690	9,490	10,398
1969	8,707	9,560	10,447

Unit Efficiency Trends

The changes in unit efficiencies during the 22 years prior to 1969 resulted in the best U.S. plant heat rate reported up to that time decreasing from 10,600 Btu/kwh to 8,690 Btu/kwh. In 1969, however, the best plant heat rate was 8707 Btu/kwh. These changes are also shown on Table I–1. The progress in unit heat rate is the result of improvements in temperatures, pressures, reheats, and size increases. Improvements in unit efficiencies are expected to continue to 1990; however, the rate of decline in unit average heat rates will not be as rapid as in the past. Environmental considerations could negate some potential efficiency gains.

Trends in Steam Temperatures

Despite the apparent increases in throttle temperatures announced in the early 1960's, recent announcements indicate that there has been some regression in throttle temperatures. The maximum throttle temperature in 1962 was 1,200°F. A recent survey of units currently being designed and constructed and scheduled for service between 1968 and 1974 shows that none of these units is to have a throttle temperature above 1,000°F.

Of the 43 units with reheats included in this same survey, only three units had reheat temperatures above 1,000°F. It is significant to note that these were the only units in the survey with double reheat.

This retreat to lower temperatures is primarily due to the more costly alloys required for higher temperatures, the maintenance problems associated with these metals, and the poorer availability of boilers utilizing such high temperatures. Even though the efficiency to be gained from higher temperatures is substantial, these problems have outweighed the incentive to reach these higher efficiencies with today's technology. Therefore, the outlook for increasing temperatures in the next decade and beyond does not presently appear to be very promising.

A major technological breakthrough in materials is necessary if steam temperatures above 1,000°F. are to be utilized economically. Research and development in tube coatings may prove helpful in reducing costs and improving reliability of tube materials for higher temperatures. Future research in materials and water treatment for advanced nuclear reactors may be complementary to materials research and development to provide the technology needed for increasing steam temperatures of fossil-fired steam generators.

Trends in Steam Pressure

Currently about 50 percent of the units are being designed in the 3,500 psi class, 30 percent in the 2,400 psi class, and 10 percent in the class below 2,400 psi. There are a few units being designed from 3,500 psi to 4,000 psi pressure. In future designs the use of pressures 2,400 psi or lower will be decreasing and the use of 3,500 psi pressures will be increasing.

In fact, present technology will allow pressures to be increased above 3,500 psi, but since efficiency varies approximately as the log of the pressure, equal increments of pressure increases will result in smaller and smaller gains in efficiency. This factor makes the cost associated with pressure increases difficult to justify. However, for the very large units predicted for the 1970–1990 period some increases in throttle pressures above 3,500 psi are probable.

Trends in Reheats

Most of today's units are being designed with single or double reheat cycles which utilize a range

of 1,000° to 1,050°F. temperatures. Double reheat units are being used in some designs (see Trends in Steam Temperatures above), but there is generally a trend back to the single reheat design because the additional cost is difficult to justify due to the small increase in the overall unit efficiency.

Trends in Unit Design

Possible improvements in unit thermal efficiencies, though admittedly small, will result from lower excess air requirements, carbon losses, exit gas temperatures, and improvements in turbine cycle efficiencies. Other possible design changes to improve thermal efficiency include the following:

1. Boiler exit gas temperatures will probably continue to drop.
2. Longer last stage turbine blades to 38" for 3,600 rpm machines will be utilized in the 1970–1980's.
3. Eight flow turbine exhausts will be utilized on tandem units (2000–2500 MW projected capacity).
4. Generator efficiency improvements are expected as more efficient cooling methods are developed.
5. Improved process-to-operator communications are being developed that will aid operator efficiency which in turn should improve unit efficiency and availability.
6. Optimization of cooling tower design will be developed to a higher degree.
7. It is expected that process simulation techniques will be used to optimize the cycle process both in design and operation.

Economics of Supercritical Units

The selection of supercritical steam conditions for a large unit is an economic choice between an increase in the investment cost per kw for the unit and the resulting reductions in unit fuel, operating, and maintenance costs. At the present time the apparent breakeven point in most areas of our country is the use of 3,500 psi, 1,000°F. steam with single reheat. The economics of increasing the temperature are not very favorable. There are basically no technical problems with increasing the pressure, but the increased cost for changes in metal thickness, piping, and boiler feed pump designs appears to make the selection of pressures above 3,500 psi for current unit sizes uneconomical. However, the larger unit sizes of the future will in all probability enhance the economics of higher pressure and hopefully research will provide the means for economically increasing initial and reheat temperatures.

Use of Combined Cycles

During the past twenty years, research and development has been conducted on the use of gas turbines in a combined cycle with gas and coal-fired units. Also, there have been some proposals that MHD generators be used in a combined cycle with a fossil-fired plant. Practical applications of the gas turbine-fossil-fired combined cycle concept have been made. One of the problems has been in the difference in availabilities of the gas turbine, steam generator, and turbogenerator. Another problem has been the limit in maximum available size of the gas turbine. It is expected that the gas turbine fossil-fired combined cycle will play a relatively insignificant role in the generation of energy in the 1970–1990 period. However, if a method were developed so that coal could be used directly as the fuel source for the gas turbine, this prediction could prove inaccurate.

Trends in Load Changing Ability and the Use of Large Units for Cyclic Operation

The economics of large units favor their use for base load capacity; however, on most systems it will not be many years before these large units will be relegated to peaking duty and will need to swing from full load to minimum load three to seven times during each week of operation.

In addition, the advent of large nuclear units that will be principally base loaded will make the load changing and startup ability of the fossil units even more important. Controls are already better designed for once-through boilers than they are for the drum type boilers although highly developed systems are also being applied to drum types. It is expected that controls will continue to be improved so that automatic boiler startup will become a reality.

To peak the large units, daily startups may be necessary. A major problem that remains to be solved before this can be done is the startup system pressure reducing valve damage that occurs. At present, once-through boiler startup valve systems have a relatively short life and will be a real problem when peaking is attempted. More input information which will afford closer surveillance of all large equipment during startup transients will permit better control.

Possible changes in design for units to accommo-

date better cyclic operation include the following:

1. Turbine clearances may be increased to avoid rubs.
2. Temperatures of 950°F. instead of 1,000°F. for throttle steam might be used.
3. Use of subcritical pressure in units up to 800 to 1,300 mw in size.
4. Higher boiler furnace heat releases.
5. Drainable superheater and reheater tubes.
6. Special design consideration for air removal during startup to eliminate oxygen from the condensate.
7. Improved controls properly designed for cyclic operation.
8. Improved designs for maintaining feedwater quality during startup.

Automatic Control of Generating Plants

The majority of new units now being installed have, in addition to conventional instrumentation, a data gathering system based on the digital computer. These in-plant systems are incorporating the basic functions of scan, alarm, trend, and log with increasing degrees of sophistication to include sequential events monitoring, post mortem review, heat rate calculations, and deviation from standards. Some systems have included degrees of digital control function such as automatic turbine startup. Because the computer functions are critical to continued operation, backing up the computer is essential. Various backup methods can and will probably include conventional instrumentation for critical items, or overlapping computers for multiunit stations, or a backup computer for single unit stations. When using a backup computer, the second computer could normally carry only the essential functions.

Status of Automatic Controls

The types of automatic controls take on several connotations, and the degree of automation ranges in the following steps:

a. A conventional analog control system using electric solid state logic in place of the older conventional pneumatic systems.

b. A conventional system as outlined in a. above with digital equipment controlling the startup and loading to minimum load and the shutdown from minimum load.

c. A conventional system as in b. above with the digital computer also controlling various sub loops.

d. A conventional system as in c. above with the digital computer also controlling major control loops. The conventional control system provides the backup for the computer.

e. A hybrid system with conventional controls and two computers, with one computer used as backup for the other computer.

f. A conventional control system in which the computer is used to integrate the system and to originate signals that will place auxiliary equipment in or out of service. The actual startup or shutdown of the auxiliary equipment might be controlled either by wired logic or the computer.

Simulated control analog equipment can be integrated with the analog system to provide operator training either prior to initial operation or during unit outages. The complexity of the controls and the lack of opportunity to use the controls require more advanced methods of operator training. Simulators can help fill this requirement. Such equipment has been developed to the point where complete boiler cycles can be simulated, providing an opportunity for setting the controls prior to shipment from the manufacturer and, in addition, providing greater opportunities for debugging the equipment.

Benefits from Computerized Controls

The benefits that can be derived by using computers as a control tool are a result of the computer's ability to analyze large amounts of input information coupled with the ability to vary the control responses based upon this greater knowledge. The effect would be to gain in varying degrees some or all of the following benefits:

a. Improved operation and efficiency. That is, better control of the individual components that affect the balance of the input–output of the station, and the optimization of control set points.

b. Safer operating procedures, since the control can have a greater number of inputs, and responses are faster and can be tempered by this greater amount of information.

c. Possible reduction in the number of operating personnel.

Wired logic systems have been used on burner control, soot blower control, turbine governors sub loops, etc. The input can be digital signals only or a combination of digital and analog. Improved control would result from the system being able

to digest more input information prior to generating an output control signal.

Automatic Burner Controls

The majority of the large steam generators being placed in service today include some form of automatic burner control. The degree of automation purchased usually is a function of the fuel used and the related economics.

Automatic burner control with flame detection has for some time been reliable for gas and oil steam generators. The simplicity of the operating systems and relative cleanliness of the fuel have reduced the problems to manageable levels. Consequently, it has been possible to provide flame proving systems, purge systems, interlocks, trips, and controls with a high degree of reliability at a reasonable investment and cost. As a result, automation for gas and oil has been developed to the point where the operator can initiate the demand for fuel from a single push button, and by observation of control lights and indicators, monitor with confidence the performance of the equipment.

The automation of burner controls for coal firing has not yet matched that of gas and oil. Perhaps the most common system being installed today is remote manual control where the operator participates in each step of the procedure. The operator's decisions are based on flame detection and instrumentation; however, such decisions are controlled by sequential interlocks.

The required number of input signals for coal burning equipment is perhaps triple that for gas, so at this point the reliability of the system is not only based upon flame detection technology but upon the reliability of the additional limit switches, logic contacts, damper position devices, and general instrumentation needed.

Although automatic startup of a pulverizer has been realized, its actual use has been limited due to operating and hardware problems. The application of such modern developments is usually applied to the more efficient units of a system. These advanced systems are generally not usable until several years after installation.

Flame Detection

Flame detection appears to be reliable and has a reasonable maintenance cost when used on gas or oil-fired steam generators. With coal firing, there appear to be two concepts. One is to look at the total flame in the furnace rather than at individual burners. The second concept is to provide a redundancy of detectors for individual burners. Two or more signals are required to prove the flame. Correspondingly, loss of one signal does not trip the pulverizer.

Problems with the use of flame detection on coal-fired units do not arise from detector technology per se but from the application of the equipment. These problems include such things as difficulties in igniting coal, variation in point of coal ignition, changes in coal characteristics, masking of the primary combustion zone by solid fuel particles and difficulties in discriminating the flame of individual burners. In addition, there are the everyday problems of dirt deposits, slagging, purge air failure, and calibration. The final acceptance of the flame detector as a basic operating tool for coal-fired units must take into account all of the above items.

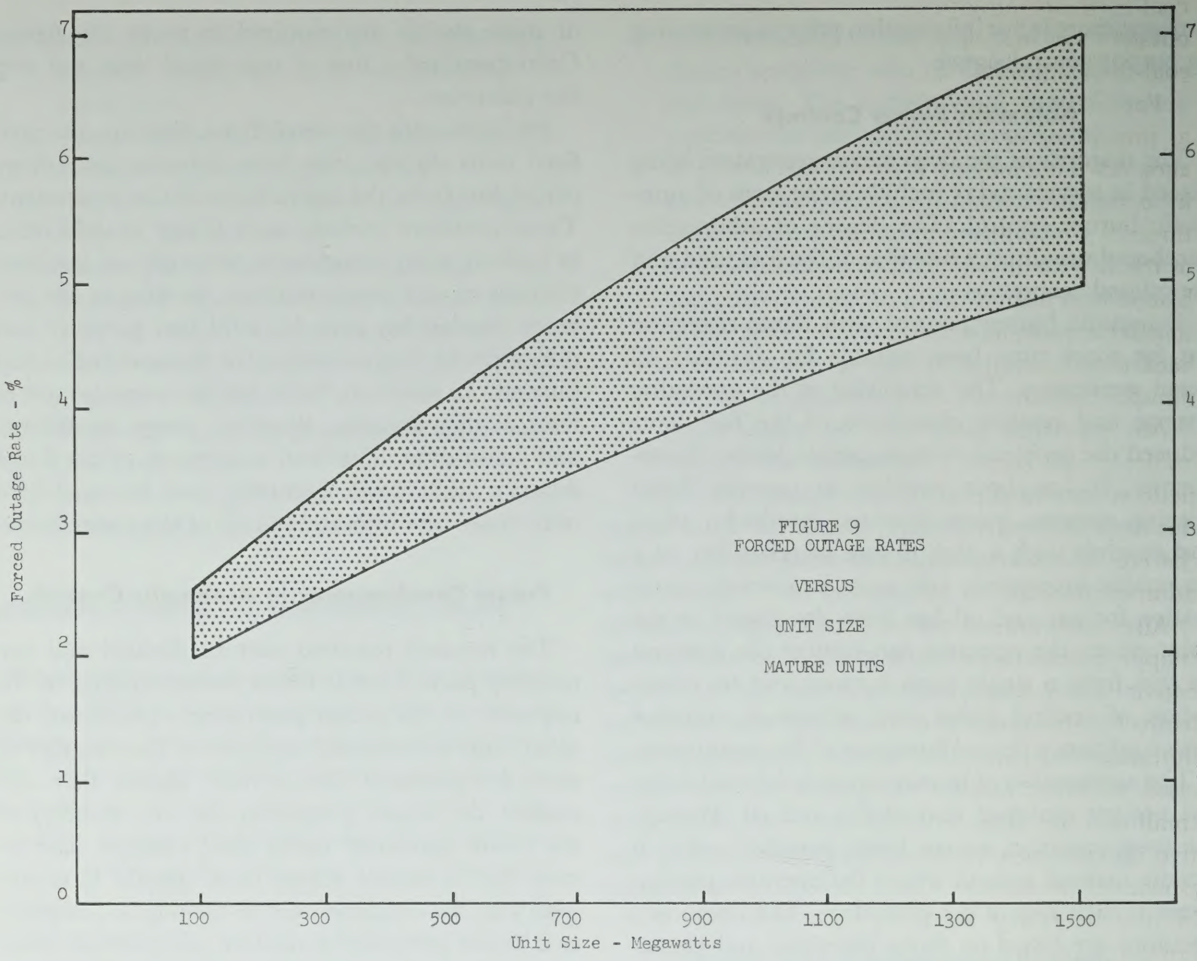
Future Developments in Automatic Controls

The research required may be divided into two primary parts. One is better understanding of the responses of the steam generating equipment, the other, improved control equipment. Existing analog control equipment can provide signals that will control the steam generator, but the stability of the steam generator under load changes may be such that it cannot accept these signals. It is possible that the continued use of the digital computer as a steam generator simulator will provide information for better controls.

In generating plants, safety and reliability are almost synonymous. If automation on a large scale is to become a reality, the reliability of the control systems must approach one hundred percent. Since one hundred percent reliability is not possible in a single control system, then the alternatives are redundancies, such as a spare computer, backup systems, or hybrid systems. It is unrealistic to consider either a unit trip or hand operation as alternatives in the event the control computer is out of service.

The cost of automation increases with the complexity of the system. Outlined below are some of the ways the cost of subsystems may be reduced:

a. Reduce prepurchase engineering costs. The specification writing and bid evaluation currently appear to be taking a disproportionate share of the cost of facilities.
b. Reduce the cost of programming in spite of the fact that most stations have different designs and concepts.
c. Design the equipment so that it can be maintained by the average technician over the life of the generating station.



d. Increase the reliability of the automation equipment so that backup controls can be minimized.

Availability of Units

Recent unit history indicates that the maturity period (time required for the forced outage rate to begin leveling out) of the large units may be as much as four years for units with drum-type boilers and five years or more for units with once-through type boilers. There also appears to be a tendency for forced outage rates to increase with unit size. This is shown in Figure 9.

The forced outage rate of turbine-generators in recent years has been about 1.25 percent. This level will probably remain the same for several years since the "building block" approach of design results in components of similar design being installed as unit sizes increase. By using this design concept some design problems have already been corrected, and maintenance is simplified. This trend may change for the large unit sizes predicted for the 1975–1990 period. More serious consideration of system design will have to be made to insure unit and system reliability with very large units.

Boiler outages appear to be the chief cause of forced outages as unit sizes increase. Outage data indicate that pressurized furnace units increase forced outage rates. Chief contributors to forced partial outages by boiler auxiliaries at present are the forced draft fans and the coal pulverizers. This trend is expected to continue. Water wall tubes and superheater tubes affect forced outages about equally. Data collected indicate that outages caused by pressure parts in the boiler are no higher for the supercritical pressure units than for the subcritical pressure units. Steam generator technology of supercritical units therefore, seems well established. Boiler controls are a substantial factor in increased outage rates. This trend is not expected to continue as control design is perfected.

Gas-fired units do not require the complex fuel

handling and ash removal equipment needed for coal-fired operation; hence, large gas unit forced outage rates are significantly lower than those for coal-fired units.

For units so equipped, the once-through boiler at present is the major contributor to forced outages. After the industry has gained more experience in designing, building, and operating the once-through type boiler, it is expected that availability of the units will increase. It is expected that units placed in service during the 1970's will show substantial improvement in forced outage rates as feedback from operating units produces improved designs for second and third generation units.

An important factor in the poor initial availability of the recent large units has been the poor performance of supercritical unit controls. This is due at least in part to not adequately checking out the controls during construction and initial operation of the unit.

After such units reach some degree of maturity, it appears that large units will have highly sophisticated control systems that will perform very effectively. However, on units with a high degree of automated control, caution will have to be exercised to avoid costly operator errors due to the small number of operating personnel and the relative inexperience with the large units. Operating personnel for such units should be highly trained in unit operating procedures and be thoroughly familiar with the unit being operated.

It seems apparent that larger units will require longer maintenance periods during overhauls unless steps are taken to reduce outage time by changes in equipment design, by improvement in maintenance techniques, by utilizing extra work shifts, or by partial overhauls scheduled at intervals. Therefore, large units will complicate the scheduling of planned outages and will require greater coordination of outages among neighboring electrical systems to optimize the reserve and maintenance requirements. The problem of maintaining adequate, well trained manpower needed to expedite maintenance overhauls will lead to the use of new techniques and new labor saving devices.

The present trend to unit inspection of only portions of the unit equipment during any one outage will continue to occur, thus encouraging the trend to "building block" turbine design. The extensive use of advanced instrumentation on all equipment should eventually lead to less frequent inspection type outages since the greater amount of data available could be used to predict impending failures.

Reliability Considerations

Examination of the state-of-the-art of bulk power supply reliability discloses that close coordination of planning and operation among electric utilities is greater today than ever before in the 88-year history of the electric power industry. Systems began experimenting with parallel or synchronous operation almost 50 years ago, but the poor frequency regulation in terms of today's standards produced swings in tie-line power flows which were difficult to control by manual regulation of the prime mover governors. Scheduled transfers between systems could not be maintained and in some instances the power actually flowed in the opposite direction from that scheduled. A period followed in which manual control was replaced by automatic frequency control at a master station. This was unsatisfactory because it placed an undue burden on the regulating station and did not solve the tie-line problem. Out of these attempts a method of operation evolved known as "tie-line bias control" which, with improved governor controls, makes today's extensive networks feasible.

Close coordination, which has been recognized as essential to obtain power system reliability, has been achieved through committees, task forces, and study groups composed of members from the participating utilities. These have organized to set forth reliability criteria and guides for studying and operating the interconnected systems and to conduct joint operation and planning activities with the overall objective that power system weaknesses that could cause uncontrolled, cascading interruptions will be detected and corrected. In addition, many companies have signed reliability agreements with their interconnected neighbors for emergency assistance.

Many thousands of miles of extra high voltage transmission lines have been constructed in the United States since 1965 and more are planned. In addition, extra high voltage interconnections have been planned and constructed as required by the interconnected system needs.

Adequate and properly distributed spinning reserves greatly enhance power system reliability. Recognition of this has led to studies to determine the needed amount and location of spinning reserves in terms of system characteristics.

Many utilities have initiated extensive load shedding programs as a means of avoiding system blackouts. The amounts of load to be automatically shed have been studied and carefully distributed throughout the systems in critical areas. Automatic

load shedding applications may vary between systems, but generally this has been done with underfrequency relays.

Among the many other steps to obtain improved system reliability are revisions of normal and emergency operating procedures, development of more comprehensive operator training, provisions for sources of emergency startup power and power for lights and communications at control centers, design of relay schemes with minimum complexity such that they themselves do not constitute a limiting factor, and augmentation of a program for inspection, maintenance, and testing to achieve the full potential for reliability.

Increasing interest in improved reliability of data now being collected will be more fully utilized to analyze the causes of outages and their probabilities of occurrence. Steps toward improvement could include the installation of redundant instrumentation, spare auxiliary equipment and controls, more sophisticated controls, etc. Manufacturers will continue to contribute to the state-of-the-art with improved equipment such as fast response and reliable generator voltage regulators, circuit breakers, relays, and other power plant equipment. Also, control and startup system design of once-through units will continue to be improved and eventually all new fossil-fired units will be equipped with automatic burner controls for safer operation and reliability. More experience in the design and operation of the larger generating units with their increasingly complex auxiliary systems will result in improved unit forced outages rates and, consequently, greater system reliability.

The use of the digital computers for interconnected system operation will be expanded in the future to handle the many and complex operating problems that are the direct outgrowth of improved technologies in the electric power field. Envisaged for everyday operation are computer programs for var dispatching, system security, substation monitoring including automatic operation of breakers, and increased logging and displays.

The digital computer will be the major tool used for the continuous monitoring of the stability and security of the electric power system. The digital computer will continuously sense the status of all major transmission and generation facilities and, upon the loss of any of these facilities, immediately analyze the situation and take corrective actions to alleviate any conditions which could cause a more serious cascading of events.

Transmission system planners and operators have become increasingly aware of the importance associated with preventive measures to guard against area-wide interruptions. This will require a continuing program of research and development. In the past, transient stability of power systems has been improved through research and development to obtain faster circuit breaker operation. The need to improve transient stability will continue; therefore, it seems that the continued development, application, and field testing of fast operating valves on steam turbines and dynamic braking by the momentary application of resistive loads near the generator will offer the route of continuous improvement in power system transient stability.

Cooling Water Requirements

In recent years there has been a growing public concern that the growing quantity of waste heat from more and more power plants is potentially harmful and could threaten the existence of many forms of aquatic life. With the enormous cooling water requirements of large power plants, the increasing demand for cooling water by industry, and the fixed amount of available cooling water, it has become apparent that more effective management of water resources must be exercised. The question which must be answered is, "What criteria or set of criteria must be satisfied in order to have effective water temperature control?" The intent of water temperature control is to assure that the quality of the water environment will protect both existing and potentially beneficial water uses. In addition to the protection of aquatic life, this purpose should include the present and future compatible use of the streams for industrial cooling water requirements. Therefore, the criteria selected must achieve a balance among all needs and should be no more restrictive than absolutely necessary, so as to promote and permit responsible industrial growth. Further, the standards selected should be based on sound biological and economic studies so that the standards are not subject to constant revisions. A constantly changing standard makes industrial planning difficult and can unduly penalize responsible industries.

Many guidelines have been studied and proposed by various governmental and interstate organizations. The Water Quality Act of 1965 required the states to establish water quality standards and a plan for implementation for interstate and coastal waters. These standards were submitted by the states to the Department of Interior for review and adoption as Federal Standards. As of

October 1968, the standards for 45 states have been approved in whole or in part by the Secretary of Interior[2]. Perhaps the most comprehensive review of water quality requirements was "Water Quality Criteria,[3]": a report of the National Technical Advisory Committee to the Secretary of the Interior.

The Committee on Water Quality Criteria noted that with respect to the full impact of waste heat on water quality "the unknowns still far exceed the knowns in water quality requirements—even to the experts." Also, the committee responsible for establishing the water quality criteria emphasized that the report "is not sufficiently conclusive or inclusive to serve as the only guide in determining water quality criteria or requirements. Regional variations in climate, topography, hydrology, geology and other factors must be considered in applying the criteria offered by the committee to the water quality standards in specific localities."

When suitable criteria are applied to specific streams, the economic impact of water quality control can be assessed. The choice of the cooling arrangements will be determined by the application of the specific standards to a particularly desired power installation and to specific site characteristics.

The prediction of temperature change in the receiving waters is complicated by the many variables in meterological and hydrological conditions which affect the rate at which heat is transferred to the environment. This implies that a complicated sophisticated analysis technique is required to assess the adaptability of a particular site to the desired power installation, water quality standards, and the type of cooling system best suited to the conditions.

Once-Through Cooling

If the total flow of a stream or total volume of a lake is adequate to absorb the heat discharged without violating the applicable water quality standards, circulating water schemes can be designed to prevent local stream temperatures from exceeding the criteria. The design of condensers to pass a larger volume of cooling water with a subsequently smaller warmup may be acceptable. Normally, a modern fossil plant will reject through the condensers some 45 to 50 percent of the total heat input and would require about one cfs of circulating water per mw of installed capacity. However, the temperature of the effluent would be between 20°F. and 25°F. above the condenser inlet water temperature. By doubling the condenser flow this temperature increase could be halved. However, the larger volume of cooling water requires larger pumps, intake and discharge conduits, condensers, and changes in station design to accommodate the larger condenser.

An alternate solution to increasing the flow through the condensers in order to decrease the temperature of the outflow is to pump additional water into the condenser discharge canal. This solution assures complete mixing of the effluent with the cooler river water and reduces the lateral temperature gradient at the outfall. This scheme may be economically attractive in applications where cold water can be obtained adjacent to the discharge canal. However, if it is necessary to build a long conduit to prevent recirculation, the costs can be prohibitive.

If a deep river or reservoir is available or in applications near the ocean, some biologically beneficial effects may be realized by taking water from the cold bottom water layer and returning the hot effluent to the same level. There may be a side benefit from this method. Large lakes and reservoirs naturally stratify as a result of solar heating and the lower density of warmer water. The oxygen demand imposed by settling planktonic debris and the lack of mixing with the top water can result in a substantial reduction in dissolved oxygen in the bottom waters. The introduction of warmer water to this layer will result in some of this water being heated by convection and conduction. Consequently, this water will rise to the surface where the level of dissolved oxygen can be replenished. However, discharging bottom water, rich in plant nutrients, into the surface layer can result in objectionable algae growth in the surface layer and a still greater "rainout" of planktonic debris into the deeper water.

By properly designing a wide discharge conduit it is possible to spread a thin hot layer of discharged water over the surface of the receiving waters which cools rapidly by evaporation. While this scheme will not upset the lower temperature layers and achieves a more rapid cooling rate, the surface layers may be too hot for aquatic life and could be objectionable to those using the water for recreation. Consideration should also be given

[2] *Considerations Affecting Steam Power Plant Site Selection* sponsored by the Energy Staff, Office of Science and Technology, page 40.

[3] *Water Quality Criteria,* Report of the National Technical Advisory Committee to the Secretary of the Interior, Federal Water Pollution Control Administration, April 1, 1968.

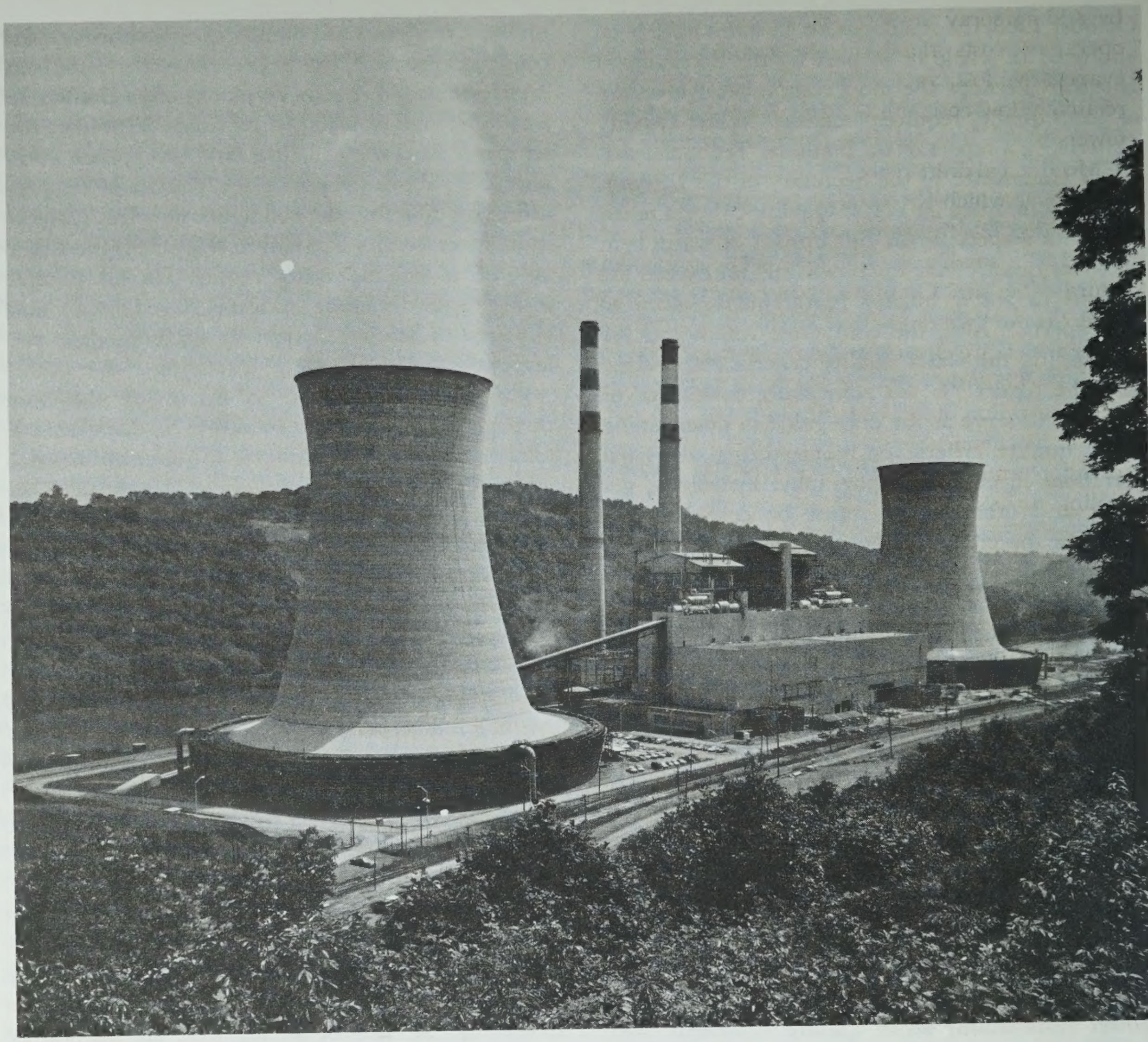


FIGURE 10.—Monongahela Power Company's Fort Martin Power Station showing the natural draft hyperbolic cooling towers used in conjunction with the two 500-mw generating units.

to recirculation problems and problems encountered with water cooled engines used for river traffic before applying this alternate.

For plants located on streams regulated for hydroelectric power production, or other water uses, a coordination of releases to achieve both hydro power production and a large cooling water supply may result in an efficient electrical system arrangement.

Cooling Ponds and Cooling Towers

Where none of the above schemes are adequate to allow compliance with the established water quality criteria, other cooling techniques should be adopted. Among such methods are: cooling ponds, spray ponds, mechanical-draft cooling towers, natural draft hyperbolic cooling towers, and dry cooling towers. Except for the dry cooling towers, all depend primarily on evaporative cooling to dissipate the waste heat. In the "wet" towers the cooled water temperature approaches the wet bulb temperature of the air, and, generally speaking, the heat transfer per unit area is much higher than in dry towers.

Cooling ponds already have wide application in the southwestern portion of the U.S. In these areas streams and wells are used to supply the makeup water lost by evaporation. The extensive land areas necessary for ponds are available in the southwest at relatively low cost, and the low humidity promotes more effective surface cooling. The cooling capacity of ponds may be increased

by adding spray units. Cooling ponds have lower operating costs than cooling towers, have less evaporative loss, and, where land is available at a relatively low cost, are less expensive than cooling towers.

Mechanical draft cooling towers force air through "fill" over which the water runs as a thin film or falls as droplets from tray to tray. The hot water is cooled as a small portion evaporates and tends to saturate the air. One of the problems with such towers is the "windage," or the droplets of cooling water which are carried to downwind areas. Windage is particularly troublesome because it contains a concentration of minerals from the source supply as well as chemicals to prevent biological fouling, corrosion, and structural deterioration. Mechanical cooling towers are reported to cost $5 to $8 per kilowatt of capacity more than for once-through cooling for fossil fuel plants,[4] but some members of the electric power industry think these are minimum costs.

Due to the extensive land area necessary for mechanical cooling tower application at large plants, the pump and fan power costs, and the problems resulting from the discharge of large quantities of water vapor near ground level, the use of hyperbolic natural draft cooling towers has been adopted for installation, where needed, on the larger units. The chimney effect of the high tower induces the passage of air through the "fill" area. The effects of windage are reduced by the longer path up the towers and the greater height at which the air is discharged. Cross flow or counter flow air and water paths are utilized in natural draft cooling towers. Hyperbolic towers cost in the order of $10 to $15 per kilowatt of capacity for fossil-fuel plants.

Another means of heat dissipation, and one which avoids the problems of fogging, mist, and icing, is the "dry" or "closed circuit" tower. These towers depend on the convective transfer of heat to air as it passes through a fin-tube heat exchanger. Dry towers approach the dry bulb rather than the wet bulb temperature and, therefore, cannot reduce the condenser water to as low a temperature. Since this mode of heat transfer is less effective than the evaporative process, a large heat transfer area is required. Consequently, the cost of dry towers at $18 to $32 per kw is two to three times the cost of comparable capacity wet towers at modern fossil-fueled plants. However, they avoid all discharge of heat to surface waters and do not require any makeup water.

No dry towers have yet been installed at major thermal electric power plants in the United States. With the possible exception of a very recent (1971) installation at a 200 mw plant in South Africa, the largest hyperbolic dry tower in operation today is at the 120 mw Rugeley Power Station of the Central Electricity Generating Board in England. This plant used the patented Heller system in which jet condensers are utilized instead of the conventional tube and shell type condenser. This system is shown schematically in Figure 11.

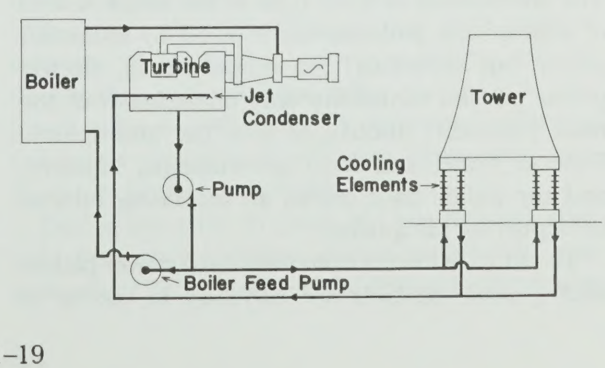
A comparison of cost figures reveals that where sufficient water is available for makeup purposes, evaporative cooling is appreciably more economical than air cool ng for thermal electric power generation. One reason is that the higher summer condenser inlet water temperature resulting from air cooling would require a larger turbine generator set to obtain the same maximum output. The increase in the total cost of power if air cooling is used in place of once-through cooling has been estimated at about 15 to 20 percent. Another recent study indicated an increase in total cost of power of about 10 percent for a dry tower instead of a wet tower.

Many areas of the problem of disposal of waste heat need to be investigated and researched. The most pressing are as follows:

1. Additional research is needed to determine the exact biological effect (beneficial and detrimental) of temperature on the aquatic community. A number of research projects are under way or planned. One example is a proposed project sponsored jointly by TVA and the Water Quality Office of the Environmental Protection Agency at the Browns Ferry Nuclear Plant in which a

FIGURE 11

CLOSED COOLING WATER CYCLE



[4] *Report of the Committee on Water Quality Criteria*, Federal Water Pollution Control Administration, U.S. Department of Interior, April 1, 1968.

controlled experiment is to be implemented. The aquatic population is to be observed and compared to see what effect exposure to heated effluent has on the biological processes when compared to a controlled community that is exposed only to the natural temperature environment. The results of these studies and experiments should be valuable in determining the adequacy of proposed water standards. Until it can be shown that particular temperature levels must be maintained in order to sustain the desired mixture of aquatic life based on sound judgment and controlled experimental data, the "unknowns will continue to exceed the knowns" in water quality control.

2. The overall efficiencies of steam plants are not expected to show drastic improvements (or reductions in the heat rejected from the cycle) in the foreseeable future. Therefore, if methods could be found to make beneficial use of low level waste heat, this would reduce considerably the amount of heat which must be absorbed by the water and atmosphere around us.
3. Further development of models and analytical techniques for predicting heat dissipation and the transport and behavior of heated water in streams and reservoirs would allow more accurate determinations of this phenomena and allow a better utilization of natural cooling for power plant and industrial uses.
4. Development of more effective and more economical methods of water cooling.

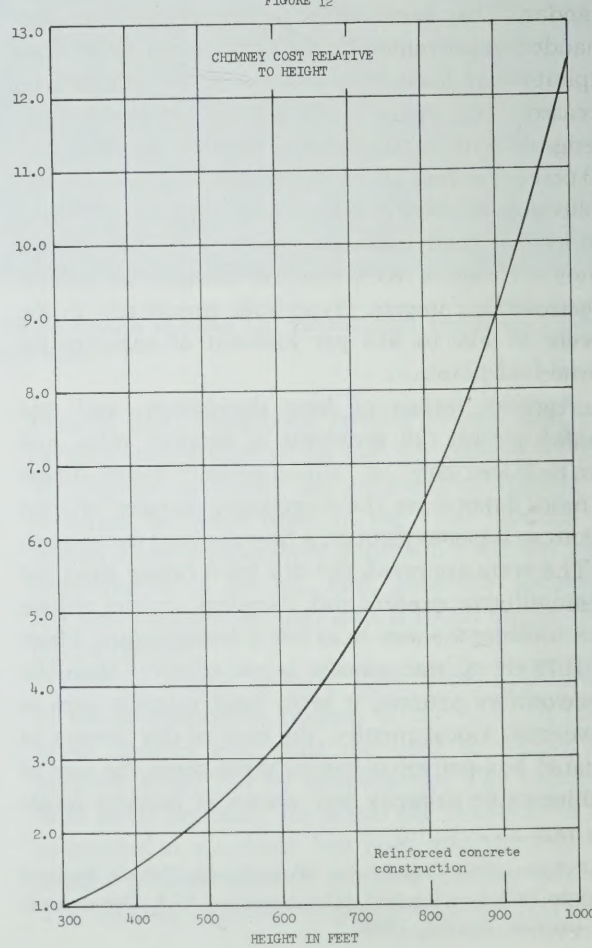
Air Quality Control

The sources of air pollution in the earth's atmosphere are mainly the result of man's activity. During the past decade the public has become increasingly aware of the dangers of air pollution. The combustion of fossil fuels is the major source of atmospheric pollution contributed by industrial plants, but according to a recent survey, electric power utilities contribute only one-seventh of the total pollutants discharged into the atmosphere. Federal, State, and local governments, industry, and the public have shown an increasing interest in improving air quality.

To reduce effluents from fossil-fired power plants, four general methods are currently in use or in various stages of development, as follows: (1) chemical and physical treatment of fossil fuels to reduce the sulfur content before combustion; (2) use of mechanical and electrostatic fly ash collectors to remove ashes, dust, and other particulate matter from the exhaust gases; (3) chemical and physical treatment of exhaust gases to remove sulfur oxides; and (4) use of high stacks to improve the dispersion of the exhaust gases into the atmosphere and avoid high ground level concentrations of noxious gases. Research into methods of reducing NO_x emissions is being undertaken. Some other factors which can contribute to improved air quality are furnace and stack design, proper plant layout, and careful consideration of meteorological conditions found at the plant site. If satisfactory means of improving the quality of stack emissions are not developed, the establishment of air quality standards would limit the size of the fossil-fired generating units and stations in the future.

During the past 15 years there has been extensive research and applied field studies to determine the parameters of chimney design to achieve adequate

FIGURE 12



dispersion of exhaust gases into the atmosphere. As unit sizes and the power plant sizes have been increased, the quantities of exhaust gases to be discharged into the atmosphere at a single location have increased. One of the methods used to achieve adequate dispersion of exhaust gases is the use of taller stacks or chimneys. The relationship of cost versus stack height can be seen from Figure 12.

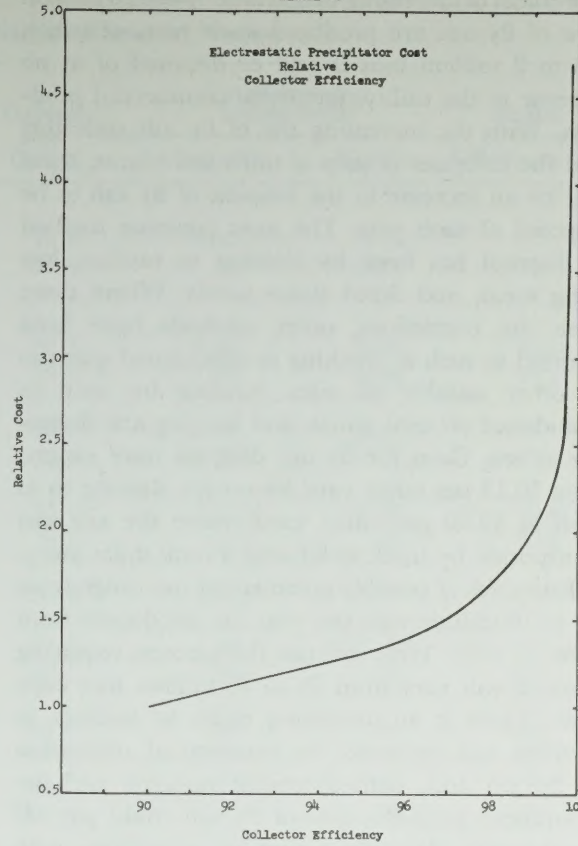
The use of high stacks has led to additional problems. A high stack in the vicinity of an airport is a hazard to air traffic. The corrosive action of the sulfur dioxide when combined with moisture laden air causes sulphate attack of the chimney lining. Some of the recent chimney designs utilize an independently supported brick lining with ventilation space between it and the outer shell; others utilize free-standing insulated steel liners within the concrete stacks. The design and construction of stacks with these features and with the ability to withstand earthquakes can become quite expensive.

Fly Ash Collectors

As the concern for a tighter control of air quality standards has increased and the public has demanded improvements, the use of electrostatic precipitators at fossil-fired generating plants has increased. Ten years ago most precipitators were designed with a particulate removal capability of 90 percent or less. During the past decade the design collection efficiency of many electrostatic precipitators has been increased to 98 and 99 percent. Figure 13 gives the estimated relative costs for electrostatic precipitators with different design levels of collector efficiency. Those who are concerned with improved air quality and thus with increasing electrostatic collector efficiency express confidence that the efficiency of fly ash collection can be increased above 99 percent. This expectation is based upon continuing fundamental research on electrostatic precipitators.

The statistics of 35,900 mw of new fossil-fueled steam-electric capacity under construction by 60 U.S. utilities for service in the four years from 1968 to 1972 reveal that all coal-burning units will have electrostatic precipitators except two which will have mechanical dust collectors and which will be located in relatively sparsely populated areas, and a third unit that is pioneering a wet-scrubber system for removing sulfur oxides along with the fly ash. Surveys indicate that increased use of electrostatic precipitators with higher collection efficiencies is necessary to achieve the desired level of air quality

FIGURE 13



for the regions surrounding steam-electric generating plants. It is predicted that practically all new coal-fired generating plants installed in the future will have high efficiency dust removal equipment.

The increase in collector efficiency and the application of collectors with higher design dust removal efficiencies has revealed a number of areas where research and development are needed. As precipitators have been increased in size and efficiency, trouble has been experienced in continuously achieving the design efficiencies. Investigations seeking increased collection efficiency and reliability have been conducted involving velocity distribution, exit gas temperature, power input, surface area of collecting electrodes, number and arrangement of bus sections, rapping intensity and frequency, sulfur content of fuel, and gas conditioning with various materials. Changes have been made in collector plate spacing, power supplies, velocity distribution patterns, and other variables to improve collector efficiency. A concerted effort to reduce the cost of high efficiency electrostatic precipitators would be desirable.

During the past 25 years, fly ash disposal after collection has not been a serious problem in most areas of the U.S.; however, the disposal is becoming

a problem of increasing magnitude. Some 20 million tons of fly ash are produced each year, of which 1.5 to 2 million tons is sold or disposed of at no expense to the utility, for use in commercial products. With the increasing use of fly ash collectors and the increases in sizes of units and plants, there will be an increase in the amount of fly ash to be disposed of each year. The most common method of disposal has been by sluicing to ravines, low lying areas, and diked sluice ponds. Where there were site restrictions, other methods have been resorted to such as trucking to abandoned quarries or other suitable fill sites, hauling by train to abandoned pit coal mines, and barging and dumping at sea. Costs for fly ash disposal have ranged from $0.15 per cubic yard for on-site sluicing to as high as $2.50 per cubic yard where the ash was transported by truck to fill sites several miles away.

Estimates of possible commercial use range from 10 to 16 million tons per year for the decade from 1980 to 1990. With this use the amount requiring disposal will vary from 25 to 35 million tons each year. There is an increasing effort by utilities to develop and promote the commercial utilization of fly ash and, with successful research and development activities, uses of fly ash could pay off handsomely. Recently a number of utilities, with some support from coal companies, have joined in forming the National Ash Association for the purpose of promoting a wider commercial use of fly ash.

The field of air quality control research has grown very rapidly with contributions by industry and government. While encouraging developments have been reported frequently during the past five years, a great deal of additional research and development is needed before economic and reliable processes are available. Continuing research effort is needed on the environmental and biological effects of various concentrations of constituents or combination of products in the gaseous effluents from fossil-fired generating stations.

Continued research on stack gas dispersion in the atmosphere under various meteorological conditions is needed to extend the technology of correlating weather data and ground level concentrations of stack gas constitutents from large units with high stacks.

Several types of meteorological conditions may result in significant ground-level concentrations of pollutants. Equations have been developed for "high wind speed", "inversion breakup", and "limited-mixing layer" models, but good bases for estimating the frequencies with which these regimes or some combination of them occur and for estimating plume rise and other phenomena required for the solution of the equations are not available Thus, the ability to apply existing equations in developing design criteria for stack height is limited since there is no way to estimate reliably the frequency of occurrence of any given level of fumigation for any given stack height. An increase in studies correlating actual meteorological conditions and observed concentrations of pollutants will be required to provide such information.

There are several processes for sulfur dioxide removal in various stages of research, development, and application. The advantages and disadvantages of these processes should be established. Effective ways of reducing the costs are needed for the utilization of these processes by the power industry.

Some progress has been made in research on sulfur removal from residual oil and for some high sulfur coals. About 15 percent of the total SO_2 emitted in the U.S. results from combustion of fuel oil. The use of oil in power plants will continue to increase. If the utilities are to continue to use residual oil, a strong, continued effort on reduction of the cost of oil desulfurization is needed.

Reports of the research in removing sulfur from coal have not been encouraging, except for some specific coals.

Processes for Sulfur Removal from Fuel

1. *Magnetic or air separation of pyritic sulfur from coal, probably after pulverizing.* This effort is subject to continued study, but even if successful and economic, a high degree of desulfurization would be possible only for coals with high ratios of pyrites to organic sulfur.
2. *Deep cleaning of coal.* Careful selection of the coal washing fluid density can result in removal of higher than normal portions of pyritic material, but the proportion of coal which is rejected with the pyrites increases, and the process obviously becomes expensive unless the heat and possibly the mineral values of the rejected material can be recovered. As with the magnetic or air separation method, the value of deep cleaning of coal is limited for coals with high fractions of pyritic sulfur.
3. *Solvent extraction or gasification.* It is technically feasible to remove both sulfur and ash by solvent extraction or by one of several gasification processes. The gasified coal can be desulfurized by extraction of the H_2S

TABLE I–2

Estimated Costs of Sulfur Dioxide Removal Processes*

Process	Capital cost ($/kw)	Operating cost (mills/kwh) no credit	Operating cost (mills/kwh) Credit	Sulfur Removal Efficiency (%)
Dry limestone injection:				
55% load factor	11.6	0.82	N/A	50
75% load factor	11.6	.86	N/A	50
Limestone injection-wet scrubbing (Combustion Engineering, APCO–TVA):[1]				
55% load factor	20.5	1.42	N/A	90+
75% load factor	18.6	1.08	N/A	90+
Limestone add-on-wet scrubbing:				
55% load factor	20.0	1.41	N/A	85
75% load factor	18.5	1.10	N/A	85
MgO Scrubbing (Chemico):				
55% load factor	20.1	1.25	0.82	90+
75% load factor	18.7	.87	.44	90+
Lime add-on-scrubbing (Bahco):				
55% load factor	13.8	1.32	N/A	95
Stone and Webster/Ionics:				
55% load factor	21.0	1.39	1.06	95
75% load factor	19.5	.96	.52	95
Wellman/Lord:				
55% load factor	[2]12.6	.96	.55	90
	[3]13.5	1.05	.79	85
75% load factor	[2]12.6	.80	.39	90
	[3]13.5	.88	.62	85
Cat-Ox (Monsanto):				
55% load factor	36	2.56	2.17	85
75% load factor	32	1.44	1.03	90

Source: Adapted from Survey of Processes and Costs for SO_x Control on Steam-Electric Power Plants, Division of Process Control Engineering, Air Pollution Control Office, Environmental Protection Agency, February, 1971.

with an amine type absorbent as is done for ' sour" natural gas. The cost of clean fuels produced from coal by processes developed so far is too expensive for large scale power generation.

As regulations require more stringent air quality control, the costs of installing, operating, and maintaining the equipment will increase rapidly. Figure 13 shows the estimated relative increases in cost for providing better collection efficiencies, and Figure 12 shows the estimated chimney costs relative to height when high stacks are needed for better plume dispersion. These are the principal

[1] The Combustion-Engineering Process was designed for two specific locations and is not readily translatable to other situations. The APCO-TVA project embodies a different design philosophy and is intended to provide a broader-based capability.

[2] With acid recovery plant.

[3] With sulfur recovery plant.

*GENERAL ASSUMPTIONS USED FOR COSTING

1. Plant size: 1000 megawatts
2. Load factor (two cases):
   55% for existing plants
   75% for new plants
3. Percentage sulfur in coal: 3.5%
4. Fixed charges:
   7% depreciation
   3% taxes & insurance
   8% cost of money

Total 18% (annual percentage of capital investment)

5. Variable charges:
   labor @ $5.00/hr. × 150% overhead
   maintenance @ 5% annually of capital
   electricity @ 6 mills/kilowatt-hour
   fuel gas or oil @ 45¢/10⁶ BTU
   coal @ 35¢/10⁶ BTU
   limestone @ $2.05/ton
   cooling water @ 10¢/1000 gallons
6. Credits for by-products:
   acid (100%) @ $10/ton
   sulfur @ $20/ton
7. Heating value of coal: 11,800 BTU/lb
8. Power station efficiency: 34.1%, equivalent to 10^4 BTU/kilowatt-hour

means currently available for reducing atmospheric pollution.

Table I–2 lists seven of the most prominent processes currently under development for removal of sulphur dioxide from stack effluents. The estimated cost for each process is also shown. This table was adapted from "Survey of Processes and Costs for SO_x Control on Steam Electric Power Plants," Environmental Protection Agency, February 1971.

Reported results of research and development to remove sulfur from oil and coal and from generating plant flue gas have been based on laboratory work and small pilot plant experience. The cost of these processes is subject to wide variations, depending on size of unit, sulfur content of the fuel, whether the process is installed as initial equipment at the time the power plant is constructed, or whether it is added to an existing station, the remaining life of the unit to which it is added, and on the particular sulfur by-product produced. Reliable cost estimates for application of these processes to large power plants have not been established.

The market tends to place the seller of a by-product material at a disadvantage since the buyers know that he has to produce it and is likely to be forced by sheer quantity accumulation to dispose of it at whatever price he can get. Sulphuric acid is commonly considered as a power plant by-product of sulfur, but it offers many disadvantages to a utility considering its production—its economic shipping distance is limited and it is difficult and expensive to store in large quantities if poor market conditions develop. Thus, production of elemental sulfur is a highly desirable goal, since this material is more marketable, can be stored easily, and should be less harmful in case of accidental loss from storage than sulfur compounds.

Maintenance Practices in Generating Plants

Perhaps one of the more important and difficult tasks all utilities have to face is the scheduling of maintenance. With the massive interties and interchange agreements in effect today, the coordination and optimization of maintenance schedules are essential. Further, the projected trend to larger generating units complicates the scheduling of maintenance and requires a higher degree of planning and scheduling optimization than has been necessary in the past.

The frequency of performing prescheduled major maintenance of generating units is governed primarily by the maintenance or inspection requirements of the boiler. For large coal-fired units, maintenance is usually scheduled on an annual basis for an outage period of from 4–6 weeks, depending on the size and type of boiler. Cyclone furnaces generally require one week more maintenance time than do furnaces which burn pulverized coal. Gas-fired boilers require less total maintenance time, and the frequency of scheduled major maintenance outages is somewhat less than for coal-fired boilers. There has been a trend toward scheduling major boiler maintenance outages for smaller boilers at two-year intervals. This has resulted from experience which has been gained with smaller units.

Turbine-generators require complete inspections and maintenance about every 35,000 operating hours, or about every five years. Severe problems which may arise under some conditions, such as erosion, can require more frequent maintenance and some utilities find it necessary to perform complete inspection and maintenance every three years or about every 20,000 hours. Maintenance time is about five weeks for a tandem compound and six weeks for a cross-compound unit. There are more components in cross-compound units than in single shaft machines. This results in increased maintenance time.

The annual boiler maintenance is, of course, scheduled to coincide with the major turbine-generator overhaul. Maintenance of auxiliaries is also done at this time with the exception of coal handling equipment and pulverizers, most of which can generally be maintained while the unit is on the line. In instances where the required maintenance outage for the turbine-generator is to be the factor controlling the length of the scheduled maintenance outage, a procedure has been established so that one casing of the turbine is opened and the internals inspected and maintained during each scheduled boiler outage.

The large size units now being installed have more complex maintenance requirements. The larger equipment and complex maintenance techniques result in more supervision requirements, less efficient use of manpower and longer down times. However, the cost per unit of output is still lower than for the smaller units.

There appears to be no major difference in maintenance problems or costs with respect to subcritical versus supercritical units. The same is true of cross compound versus tandem compound units

except for the extra time required for each scheduled major turbine-generator maintenance period. However, maintenance problems are more severe with pressurized than for negative pressure furnaces. Pressurized furnaces tend to have more leaks involving more tubes because of the stresses involved. Leaks in a pressurized furnace are more serious because gas leaks into the powerhouse cannot be tolerated; whereas, small leaks in a negative pressure furnace can be tolerated for a period of time. As a result, maintenance costs for pressurized furnaces are somewhat higher and the availability is generally less.

It is expected that maintenance problems with larger units will decrease as experience is gained, and experience with the large units should also lead to improvements in design and maintenance techniques which will reduce maintenance costs. Installing units in the 3,000 mw range should not affect maintenance problems or costs any more than resulted from the proportional increases in unit capacities up to the present.

During development of interchange agreements the scheduling of maintenance between the systems must be given considerable study in order to realize all of the potential savings possible through interchange.

It is very important to consider the effect of interchange on time available for maintenance and the capability of a utility to perform the required maintenance during the time available. Otherwise, it is conceivable that a system may find it necessary to install capacity earlier than the system loads dictate in order to have sufficient margins to schedule the required maintenance. Many alternatives exist to avoid maintenance scheduling problems and yet realize the maximum benefits of exchanging power. The coordination of maintenance schedules and use of reserve capacity can allow utilities to perform the required maintenance on very large blocks of capacity while continuing to maintain a high degree of system reliability. Agreements are conceivable such that utilities can increase their capability to maintain a large number of units by using each other's maintenance crews. This would facilitate a more even use of maintenance personnel and allow each utility to minimize the personnel required to maintain its system. Several companies are now offering to do maintenance on a contract basis, and many utilities are using their services.

Inventory costs of maintenance materials and spare parts can be substantially reduced by sharing inventories for major components with other utilities. Computerized inventory records could expedite the location of spare parts in emergency situations and enable costly outages to be reduced.

The use of critical path scheduling, particularly for the first major maintenance outages for large units, could possibly improve the efficiency of the maintenance personnel and shorten the required outages. It is predicted that critical path scheduling will become an important tool in scheduling work during maintenance outage of the very large units installed in the period to 1990.

There is a need for research and development related to the maintenance of fossil-fired generating units. Some examples are:

1. Improvement of equipment such as maintenance tools and rigging.
2. Development of better materials with particular emphasis on metals.
3. Development of a closer coordination between utilities and manufacturers so that as maintenance experience is gained, more maintenance free designs could be developed.
4. Improvements of maintenance techniques and procedures.

Peaking Plants

The basic pattern of annual and daily load curves have undergone some changes in the last 20 years. Many systems that have had annual peaks traditionally in winter months are now experiencing summer loads in excess of previous winter demands. In many instances, these peaks are also of longer duration. Although some improvements in capacity factors are expected in the future, no significant changes in the pattern of annual and daily loads are expected which would alter the nature of minimum and maximum generation requirements.

Although transmission line interconnections have provided for increased reliability, the interval between the first National Power Survey and this present study has not been marked by substantial reductions in individual system reserves due to the effect of these interconnections. The relatively stable capacity factor and the demands for basic generating reserves provided for each system have led to increasing emphasis on the method of providing for reserve margin and peak load capability in peaking type generation.

As systems increase in size, the proportion of reserve and peak load capability, although of the

same general percentage, equate to larger total kilowatts and capacity. Thus, 15 percent of a 1,000,000 kw system is only 150,000 kw, but the same percentage of a 10,000,000 kw system represents 1,500,000 kw. The nature of providing for peaking capacity of increasingly larger systems entails different considerations than were needed on the smaller system. Ten 15,000 kw gas turbine units might be considered an appropriate solution for the smaller system, whereas, a hundred such units for the larger system might be entirely inappropriate.

As base load equipment becomes larger in size, for the proportionately larger system, more complex and less flexible apparatus is more readily justified. Supercritical and once-through boiler designs, together with multiple reheat installations, not only are uneconomical for load following operation but often have unique design features that do not permit variable capacity operation without jeopardizing the integrity of the apparatus. Certainly, installations that have been justified on the basis of extended base load operation are not expected to be readily amenable to daily load swinging operation unless originally designed with the dual type duty in mind.

As the industry moves toward 1990, additional peaking plants will be required. These are those plants which can be brought into service rapidly and on short notice and can be shut down quickly, as well as those units which have a high response to variable loading and can be cycled without undue stress. Because of the low capacity factor of these plants, emphasis will continue to be placed on low initial cost rather than low operating cost which is usually synonymous with high efficiency. However, as these units, which will make up from 15 to 30 percent of a typical system generating capacity, continue to increase in size, attention to economic operating and maintenance considerations cannot be avoided. There is a growing requirement for peaking plants that can be built quickly at low cost which also have a reasonable power production cost component that would not too adversely affect overall system cost.

Conventional and pumped storage hydroelectric capacity, gas turbines, and diesel driven generators, and other forms of peaking installations will contribute to meeting these requirements. Fossil-fired steam plants will continue to provide the major portion of installations for this type service, but attention must be given to the special considerations involved in the use of fossil-fired plants for peaking application.

Sizes of present steam-electric peaking units are of the order of 300 to 400 mw, about 30 percent of the capacity of the largest base load turbine generator unit. If this pattern is to prevail for the larger systems of 1990, the present size of peaking unit will have to increase to the thousand megawatt range. The use of large size units and the need for versatile operating capability are presently contradictory. High pressure and high temperature, together with multiple reheat cycles, do not allow for effective peaking and cyclic operation. Problems in water treatment and oxygen contamination of internal preboiler and steam generator unit components remain formidable.

Peaking units with initial steam conditions of over 1,000° F and 2,000 psi are not expected for the 1990 peaking plant. Increases in furnace heat release rate and heat absorption criteria for intermittent and cyclic duty might allow single furnace applications, but the problems associated with the needs for steam temperature control may in the larger sizes offer opportunities for multiple furnace installations with separately fired control surfaces. The design of the larger low pressure sections required for the 3,000 mw base load units will have applications for the 1,000 mw peaking unit.

Multiple fuel supply systems will be needed. Although natural gas and oil are the most flexible of the fossil fuels, the larger sizes of peaking plants may justify coal fired peaking installations. Although the nuclear plant offers unique opportunities for load-follow capability it is not anticipated that nuclear peaking facilities will be generally adopted until the cost of these installations become more competitive.

Fuel

The rapid trend toward nuclear generation has resulted in a dramatic change in the electric utilities' forecast for use of fossil-fuel since the publication of the 1964 "National Power Survey." That survey indicated that by 1980 nuclear capability will be supplying about 35 percent of the nation's kilowatthour generation. Current surveys indicate that this 35 percent point will be reached in the eastern part of the United States in the mid 1970's and that nuclear power will account for about 50 percent of the nation's total generation by 1990, with a corresponding reduction in the use of fossil fuels although in absolute quantity they will continue to increase.

Although availability of gas for power generation

has been influenced by the Federal Power Commission, the choice of fossil fuel to be used in any given generating unit has usually been economic; that is, which fuel will result in the lowest overall cost per kwh produced by the unit over its life. The components of fuel costs to be considered are:

a. Fuel producer's selling price
b. Transportation
c. User's handling cost
d. Conversion efficiency

To these now must be added a fifth, and at present a largely unknown component: cost of compliance with air quality regulations. A number of plants have been shifted to gas and oil operation because of air pollution regulations.

On the basis of recent industrial surveys of the three fossil fuels, the use of natural gas for electric power generation in the eastern United States will show a relatively large increase if available. The use of coal in these regions is also expected to expand substantially but, in percentage of the total generation, will lose ground due to the more rapid advance of nuclear power.

The nation's known coal reserves are more than adequate to meet all the needs of the electric utilities, and all other users, through and well beyond 1990. Of the total known reserves 43 percent is bituminous coal, over one-half of which occurs within the three eastern FPC regions and about one-third of which is in the Appalachian area. The remaining 57 percent of the nation's total reserves is made up of almost equal portions of sub-bituminous coal and lignite. These reserves most of which are low in sulfur content are found almost exclusively west of the Mississippi River. Mining costs are low, but transportation costs to the most populous areas are high because of the long distances involved.

Most of the low-sulfur bituminous coal east of the Mississippi River is found in the Appalachian region. Due to the generally thinner seams in which the low-sulfur coal occurs, higher cost mining conditions will be involved. In addition, higher prices will be brought about due to considerable competition for the product by other industries, and since the low sulfur reserves are relatively concentrated, overall transportation distances to points of use will be greater. All of these factors indicate considerably higher delivered costs for low-sulfur coal.

The long-term mine price of coal has trended downward until recently due to mechanization and improved productivity. For the future, however, it appears that the actual cost of coal delivered to the generating plants will increase. However, in order for the coal industry to retain its competitiveness in the energy market, advancements in mining and transportation techniques must continue to the extent that the long term trend, in terms of constant dollars, must be downward. Whether or to what degree this will take place is uncertain. One disturbing element in the picture is the trend toward consolidated ownership of all raw thermal energy supplies—coal, petroleum, and uranium.

The increasing emphasis on the prevention of air pollution will add to the cost of power from coal- or oil-fired plants by necessitating the use of low-sulfur fuel, or the desulfurization of the fuel at the point of origin, or the use of equipment for removing sulfur products from the flue gases. Air pollution from large coal- or oil-burning plants has been minimized in the past by the use of tall stacks, but this will not be practical for the larger plants of the future. Among the processes now under development for the removal of sulfur products from flue gases are methods by which the sulfur would be recaptured for sale as a by-product, thus reducing the economic penalty to be faced by the coal and oil industries. However, in all probability, pollution control will make the competitive position of coal and oil more difficult.

Most electric utility coal moves by rail, and here the development and use of "unit trains" has resulted in important cost savings. Further development of this concept into high speed "shuttle" trains may result in some transportation efficiencies, although rates for coal transportation are currently increasing.

The feasibility of pipeline transportation of coal has been proven by a 108-mile line which operated successfully for about four years. Recently placed in operation in the far west is a 275-mile coal pipeline, which earlier studies indicate should have total costs competitive with rail transportation. Further developments in pipeline transmission and the upward trend in rail rates may well change the coal transportation picture considerably.

Water shipments of coal have increased appreciably in recent years and are expected to continue as an important part of overall coal transportation.

Improvements in the technology of, and reductions in, the costs of extra high voltage (EHV) A-C and D-C transmission are making the transportation of "coal by wire" more attractive. It appears that within the next few years it will be economically practical to transmit blocks of 3,000–4,000 mw from mine-mouth plants to load areas

TABLE I–3

Retirements of Generating Capacity, Total Electric Utility Industry Megawatts (Nameplate)

Year	Hydro	Steam	Internal combustion	Total
1969	110	823	37	970
1968	70	690	46	806
1967	215	459	57	731
1966	51	565	53	669
1965	64	774	69	907
1964	36	534	43	613
1963	63	771	36	870
1962	79	843	46	968
1961	191	652	22	865
1960	32	455	29	516
1959	65	525	30	620
1958	15	491	52	558
1957	12	302	31	345
1956	254	307	29	590
1955	24	587	47	658
1954	19	450	39	508
1953	21	221	34	276
1952	14	142	43	199
1951	13	176	29	218
1950	17	129	17	163
1949	85	108	21	214
1948	30	71	26	127
1947	12	144	19	175
1946	81	109	16	206

Note: Includes Alaska and Hawaii for years 1963 through 1968 only.
Source: FPC Form 4 Reports.

in the range of 600 to 700 miles distance by A-C and even greater distances by D-C transmission. However, dependence of a metropolitan area for its power supply upon long transmission lines introduces reliability problems in the event of major line outages. Solution of these and other problems appears expensive and may well cancel out all or part of the savings otherwise possible.

The delivered cost of natural gas to electric utilities had remained relatively stable until 1968. This Committee's survey indicates, however, that such costs are increasing. Gas is the easiest and least expensive of all fossil fuels to handle at electric generating stations, and the burning of gas minimizes air pollution problems. However, it is becoming increasingly difficult to place long-term contracts for natural gas to serve as boiler fuel, a trend that is expected to continue. Natural gas supplies many areas of the United States today, but in the long term it is not expected to maintain its present proportion of the overall fuel market for electric generation. A national fuel policy may prohibit or severely restrict the use of natural gas for new power plant installations.

Technology is available today for shipping large quantities of gas in a liquefied state. Cost studies indicate, however, that it will be some time before liquefied natural gas (LNG) could become economically attractive to electric power utilities.

Fuel oil has never achieved a dominant position in power generation in the United States and has been of importance in power generation only in the coastal areas of the northeast and extreme southeast and southwest parts of the United States where ocean transportation makes oil competitive with other fuels. Changing demands for petroleum products and development of new refinery processes have limited the amount of Bunker C fuel oil available at favorable prices. Domestic refineries now produce more profitable products from crude oil resulting in less residual production.

On the other hand, requirements for low-sulfur content fuel require new processing facilities. Utilities have increasingly turned to oil-fired units in order to meet air quality and generation commitments and the demand for oil has increased. The uncertainty of a long term oil import policy, recent oil discoveries, transportation limitations, and similar factors made the future use of fuel oil for power generation unpredictable.

Retirement of Units

Until recently there were relatively few retirements that could be called "planned." The older units did not "die" or retire but "faded away" through continued, but diminishing, use as peaking units. The Federal Power Commission retirement data indicate an increase in steam unit retirements although the absolute values in terms of megawatts of capacity are somewhat modest. The FPC retirement figures are shown in Table I–3. In the period from 1954 to 1960, the average retirement rate was about 500 mw per year. This value increased to about 650 mw per year for the period for 1961 through 1967. The largest retirement of steam capacity for a single year was 843 mw in 1962.

Trends in Retirement Age

Many of the retirements that have taken place to date are the old relatively small units that were installed prior to the 1930's. Such equipment with its inherently high operating and maintenance costs, could not provide the systems with satisfactory peaking capacity. Consequently, the units were abandoned and a reasonable rate of retirement was maintained without the need to use a more sophisticated approach to retirement evaluation. As a result, few utilities have developed an objective retirement evaluation procedure that takes into account the pertinent factors that deserve consideration. In theory, when increasing operation and maintenance expenses and decreasing unit efficiency together impose costs which equal or exceed the cost of replacement capacity, the plant or unit is economically "obsolete" and is due for removal. In practice, an older plant may be useful as a portion of system capacity and yet be used so little that neither maintenance cost nor inefficiency count much toward offsetting the cost of replacement. Thus, plants and units tend to remain in service until some discontinuity occurs such as a need for its site, a sudden need for major maintenance, or other unexpected event. The situation will undoubtedly change in the near future with impetus for retiring the older units being provided by air pollution regulations now being promulgated throughout the country.

A more rigorous approach to the subject of retirement would undoubtedly have an effect on present retirements as well as the planned future retirements of the newer units. At present, 35 years represent the most generally accepted estimate for the average life of the fossil fuel units recently installed and being constructed throughout the country. Some serious consideration is being given by some utilities to reducing this to 30 years, while others already consider 30 years as proper. Summarizing, it would appear that if a trend were to develop regarding a change in the retirement age of a unit, it would probably be downward below the 35-year life.

Factors Affecting Useful Unit Life

Retirements to date have been based on a variety of reasons that may reflect considerations unique to a given plant location or generating system. Among the factors considered in retiring older units are the following:

a. To provide space for new and larger units due to the unavailability of reasonable site locations, especially for those systems encompassing and restricted to larger cities or heavily industrialized areas.
b. To provide space for strategic load distribution points such as substations.
c. The size, age, and physical condition of the equipment. The physical condition of many of the older units makes it increasingly difficult to depend on them even for peaking capacity. In addition, the capacity of many such units is usually relatively small, and since average unit capacities double about every ten years, the capacity contribution of such units becomes less important as the system capacity increases.
d. Economic conditions—Relatively high operating and maintenance costs, even on units serving peaking duty. In some cases replacement with special peaking equipment has proven economical. In one instance, a power system justified the replacement of the steam prime mover with a special gas turbine peaking unit based on economics, operating flexibility, and the desirability of keeping generating capacity in a key location in the distribution network.
e. Environmental regulations now being enacted by state and local governments are encouraging the early retirement of the older units because in many cases it is uneconomical or impossible to install new or improved pollution abatement equipment in order for such units to comply with the new air pollution regulations. In addition, noise abatement and esthetic val-

ues are additional reasons for early retirement of these units.

It is anticipated that in the future, retirements may be based on more formal retirement policies and procedures, resulting from consideration of such factors as:

1. Change in scheduling new capacity.
2. The cost and characteristics of modern peaking units.
3. Present and projected maintenance and operating costs of the units involved.
4. The relative ease or difficulty in intermittent staffing of units for infrequent peaking operation.
5. Effect of unit availability of new larger units on system reserve needs.
6. Cost of purchased power to replace peaking equipment.
7. Economics of newer units.
8. Incremental costs of providing additional capacity in newer units.
9. Air and water quality control.
10. Location of the older units.
11. Need for, or the desirability of, using the site of the older unit for new system facilities.

Technical Manpower

The ever growing demand for power increases the manpower requirements for design, construction, operation and maintenance of the new power plants required to meet this growth. Conversely, the increase in size of units and the greater application of automatic control systems tend to lower manpower requirements. In net total numbers, however, there will be a much greater need for trained people in the 1990 electric generating industry than is required today.

The increased sophistication in plant and control equipment will require increased technical skills at all levels. The trend that has resulted in replacing the boiler fireman by the computer control specialist will be accelerated in the future. The present shortage of technical manpower can only be overcome by diligent attention of management to the need for selecting and training competent people.

By 1990 technical personnel with at least the equivalent of a bachelor's degree in engineering will be required for operating and maintenance responsibilities, not only at the plant superintendent level but also on shift assignments. Where the majority of operating and maintenance personnel today are craftsmen whose skills are developed by on-the-job opportunity and training, the coming decades will require personnel for these positions with backgrounds of greater technical depth.

Demands for technical manpower will be even more rigorous in the areas of power plant design and construction. Engineering manhours for large size, base load generating units are currently running three to four times the manpower requirements of former, less sophisticated units. Exacting construction requirements for adherence to specifications, quality assurance, and precise execution of intricate apparatus and control systems require increasing field service, supervision, and liaison. Technical manpower in power plant design and construction, as well as in equipment manufacturers' designs, production and service organizations, does not appear to be adequately supplied from traditional engineering school sources. Not only will large numbers of people with bachelor's degrees be required, but the more complex phases of the industry will require engineers and scientists with advanced degrees and specialized training.

The power industry has only recently begun to obtain the services of a larger share of the professional, scientific, and engineering community through the challenge associated with the introduction of nuclear power and increased emphasis on the environmental aspects of power generation, transmission and distribution. The tremendous manpower needs of the industry will not be met by conventional means from conventional sources. The electric utilities will need to provide stimulus to the university and technical school programs and may have to undertake the equivalent training itself to provide sufficient technically trained personnel.

CHAPTER II
NUCLEAR GENERATION

Summary

Nuclear plants will generate an ever-increasing portion of the power requirements of the U.S. It is expected that generation costs of nuclear and fossil plants will remain close enough to each other to preserve the element of competition in most situations, and thus to keep costs to the customer at the lowest possible level. Economics of scale may result in larger units and in multi-unit plants, eventually reaching 3,000 mw units and 6,000 mw plants.

As experience is gained with construction and operation of nuclear plants, as component designs including safety systems become more standardized, and as manufacturers' production capacities are expanded, it is expected that the trend of lengthening lead times will be reversed, provided a reasonable level of labor productivity can be achieved. If this expectation is to be realized, however, the regulatory process and review by the public must be accelerated and the problems presented by emotional protestations overcome.

Active research and development programs will be pursued in many facets of the atomic energy field. Most promising is the development of breeder reactors that will produce more fuel than they consume, which will insure a long-term, low-cost supply of energy, to meet the burgeoning growth in power requirements in the U.S. and the rest of the world.

Introduction

During the past five years there have been many dynamic developments in the field of nuclear power. Increased sizes of nuclear power plant components have made possible economies in plant capital and operating costs. Furthermore, the price of competing fossil fuels including the transportation cost component has generally increased during this period. As a result, large size nuclear power plants have become competitive with fossil-fuel plants in most sections of the nation.

Orders announced from January 1966 to June 1, 1970, for nuclear plants totaled about 73,000 mw. This figure far surpassed the most optimistic estimates by the electric power industry. It is of interest to note that five years ago less than 1,000 mw of nuclear powered generation was in operation, consisting primarily of reactors of an experimental or prototype nature. At the end of 1969, the largest operational water reactor had a net capacity of 575 mw. Construction was in progress, however, for plants with unit capacities of about 1,100 mw.

A comparison of planned nuclear and fossil fueled capacity additions for the years 1970 through 1973 is given in Table II–4. It should be noted, however, that all fossil fuel additions for the latter part of this period may not have been announced due to the shorter time schedule required for such plants.

The primary factor responsible for the better economy of nuclear plants is the lower expenditure required for fuel over the life of the plant. It is expected that further reductions will be made in the future as technology is improved and as larger volumes of fuel are processed. Of course, it is not possible to predict future costs precisely, but the factors that could cause cost changes are likely to affect fossil and nuclear fuels in the same direction and nuclear power should retain its economic advantage, even in areas where coal and gas are nearby. Figure 15 indicates the locations of planned and operating nuclear plants with respect to fossil-fuel reserves.

The actual reliability of the large nuclear power plants now on order is yet to be demonstrated; however, the steam conditions are much less severe than in modern fossil-fueled plants which should result in better availability. Because of the lower steam conditions and, in the case of boiling water reactors, the absence of steam generators, reactors should experience a significantly lower forced outage rate due to tube failure which is a major cause of emergency outages in fossil fired plants. It is possible that unforeseen new problems may be encountered in the relatively new components in the

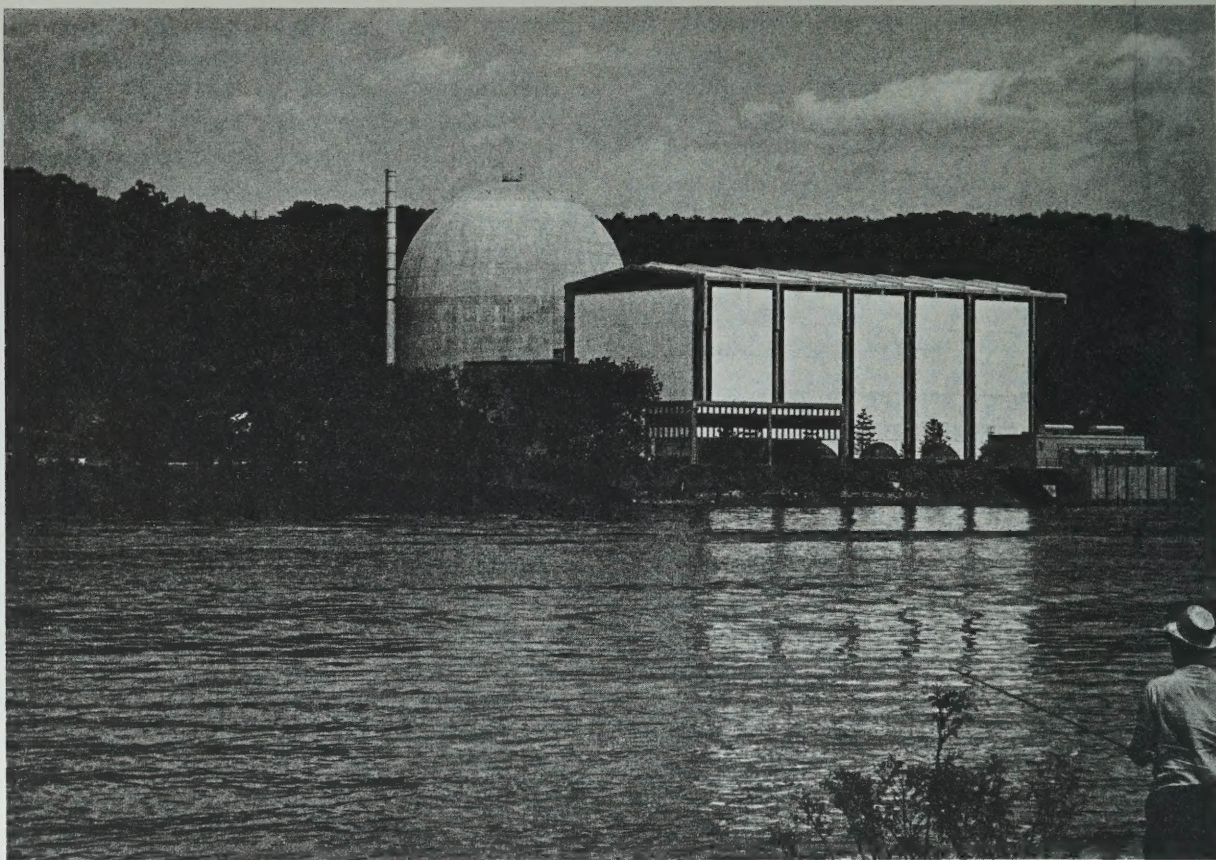


FIGURE 14.—The Connecticut Yankee Atomic Power Company's nuclear generating station at Haddam Neck, Connecticut. The 570,000 kilowatt electrical facility was built by 11 New England electric utilities who share in its generating output.

nuclear end of the plant, but the extremely rigid licensing requirements imposed on their design and construction make this unlikely.

The public has generally accepted commercial nuclear power plants at the comparatively isolated sites selected thus far, and as each plant has been placed in service and has operated in a safe manner, public acceptance has increased. There have been instances, however, where a segment of the public has voiced objection to the proposed siting of nuclear plants on the basis of their concern with the potential effects on the environment and this is developing into a major problem. The continued successful operation of nuclear plants should hasten their acceptance near large population centers which are the most desirable locations from a power distribution standpoint.

An important factor in the siting of power plants is the availability of adequate cooling water. As presently designed, a light water nuclear plant

TABLE II–4
Planned Megawatt Electric Additions

Year of commercial operation	Nuclear	Fossil	Total	Percent nuclear
1970	4,300	24,200	28,500	15.1
1971	6,500	23,100	29,600	22.0
1972	14,600	21,200	35,800	40.8
1973	15,200	20,100	35,300	43.1
Grand total	40,600	88,600	129,200	31.2

TABLE II–5
Projected Electrical Generating Capacity in USA

Year	Total generating capacity installed Mw×1,000	Nuclear capacity installed Mw×1,000		Nuclear installed as a percentage of total installed capacity		
		Low	High	Low	High	Average
1970	329	7	9	2.1	2.7	2.4
1980	658	140	170	21.3	25.8	23.6
1990	1,231	450	550	36.6	44.7	40.6

requires about 50 percent more cooling water than a fossil plant of comparable capacity. Cooling towers and associated equipment generally can be used where water sources are inadequate for once-through cooling or where the best assimilation capacity of the source is limited, but such systems usually require a greater investment than once through installations. Also consumptive use of water for cooling tower operation is a growing problem which is likely to become worse in the future.

For the long term, uranium and thorium are available in quantities sufficient to satisfy the country's electrical energy needs for thousands of years. However, in order to realize this potential, reactors which utilize nuclear fuels more efficiently than those which are currently being built must be developed. The breeder reactor will accomplish this purpose, and prudence requires a positive approach to its early and orderly development. The light water reactors currently being built in the United States utilize only one to two percent of the potential energy in the uranium fuel. With the recycle of plutonium, this percentage will be doubled. In contrast, however, the breeder reactor can utilize 60–80 percent of the potential energy in the mined uranium.

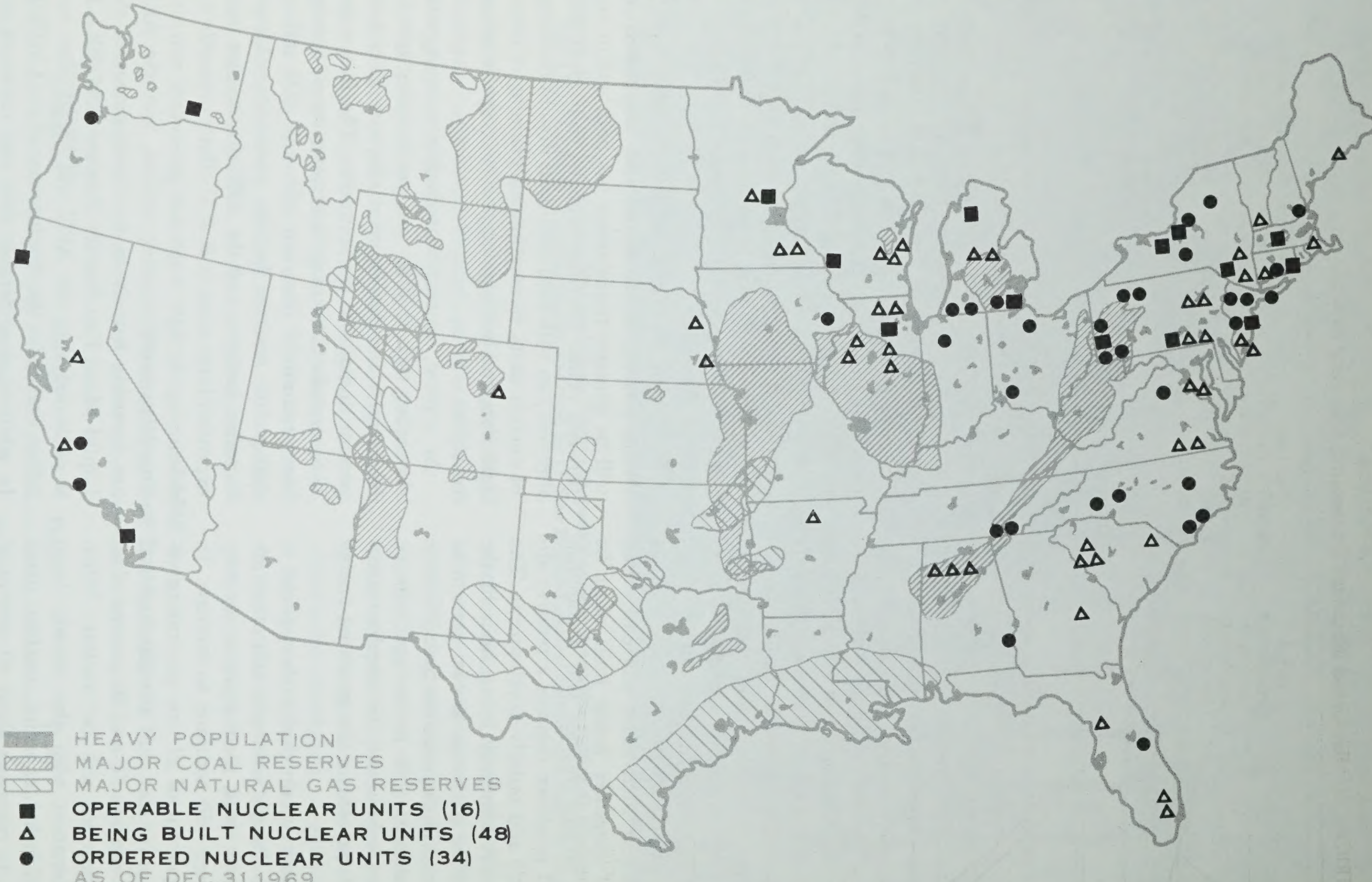
Since it is almost certain that nuclear plants in the long range will have economic and other advantages over fossil units, their share of the new generation capacity will continue to increase. In 1967, about 50 percent of all new generating capacity ordered was nuclear, and it is expected that in the year 1990 between 70 and 80 percent of all new capacity additions will be nuclear. When viewed in combination with the already large amounts of fossil-fueled capacity, nuclear plant capacity is likely to represent about 40 percent of overall capacity by 1990. Figure 16 illustrates the projected range of growth of nuclear capacity, and the relationship of nuclear units to predicted total installed capacity. The range in nuclear capacity shown in Figure 16 spans estimates made by the EEI and by the AEC. For convenience, the data for each decade is listed in Table II–5.

It is estimated that by the year 1990 the size of nuclear units will increase from the present day size of 1,100 mw to the 3,000–3,500 mw range. The maximum projected size will undoubtedly be reduced if the reliability record of mature units does not reach the levels expected by the utility industry. The increase in size, together with technological advances and increased fabrication and construction experience should bring about a reduction in the capital cost per kilowatt based on a constant value of the dollar.

It is projected that there will be more electric system pooling in the future and also that there will be stronger transmission ties both within and between pools. Ever-increasingly, individual utilities will join with their neighbors in joint financing of nuclear units, in coordinated planning of future additions, and in designing pools to improve system reliability.

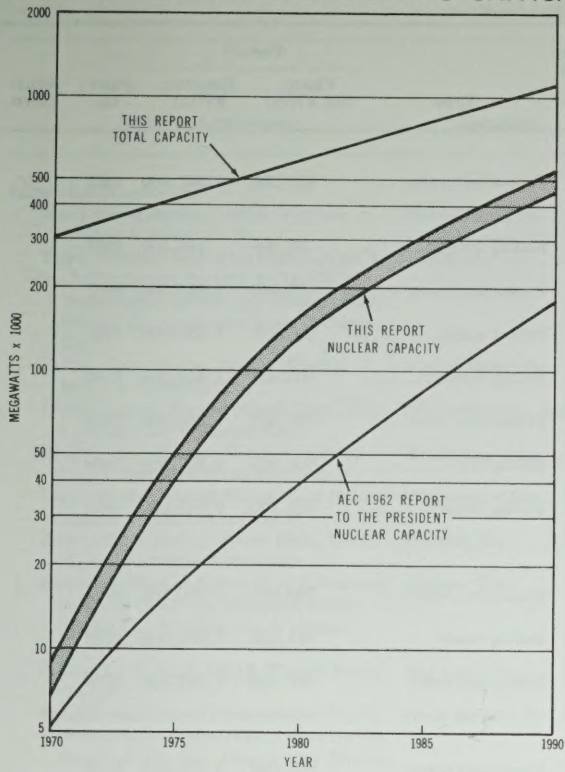
At present, reactor manufacturers are rapidly expanding their facilities and are investing heavily in research and development efforts to meet both present and future commitments. The five major U.S. manufacturers of nuclear steam supply systems have committed between 400 and 500 million dollars to nuclear facility expansion. Manufacturers, utilities, and the AEC, in the past have expended large sums in R & D efforts primarily for developing the light water and gas-cooled reactors. Presently, manufacturers, utilities, and the AEC are investing heavily in the development of the Liquid Metal Fast Breeder Reactor (LMFBR). It is estimated that the AEC will spend over two billion dollars for the development of the LMFBR. In addition, considerable time and resources are being directed toward the development of fuel fabrication facilities and chemical processing plants to provide for future requirements. By keeping abreast of the industry's growth, the manufacturing segment will be prepared to satisfy the needs of the

FIGURE 15



NUCLEAR UNIT SITING IN REFERENCE TO MAJOR COAL RESERVES, NATURAL GAS RESERVES & HEAVY POPULATION

FIGURE 16
PROJECTED ELECTRICAL GENERATING CAPACITY



utilities in the nuclear field as they have in the past for the more conventional forms of power generation.

In summary then, the nuclear power industry is quite young and has before it the possibilities of technological advancement that should result in high efficiencies of operation that will contribute substantially to the reduction in the cost of producing electrical energy relative to other forms of power conversion. Larger size units, standard components, more efficient utilization of fuel, advanced designs, and improved construction methods will contribute to cost reduction. On the other hand, longer lead time, more stringent quality control, poor labor productivity, added safety features, higher installed prices for plant equipment, and technical advances that will not permit repetitive use of existing components will tend to increase costs. These factors, together with a backlog of operating experience, will ultimately determine the accuracy of the growth predictions for the years ahead.

Types of Reactor Systems

In nuclear power plants, the generation of heat within the reactor stems from the fissioning of fuel atoms. The various reactor concepts are divided generally into either a "fast" or "thermal" classification, depending on the energy of the neutrons initiating the fission process. The design of thermal reactors employs moderating materials to slow the neutrons before the majority of the fissioning occurs, while in the fast reactor the fissioning process is initiated by neutrons with higher energy levels.

Essentially all of the power reactors planned or

TABLE II-6

Utility Electric Power Reactors as of Dec. 31, 1970

[Part 1—Civilian reactors (domestic)]

Name and/or owner	Location	Principal nuclear contractor	Type	Power[1] Plant, net kW(e)	Power[1] Reactor, kW(t)	Start-up	Shut-down
A. CENTRAL-STATION ELECTRIC POWER							
Operable:							
Shippingport Atomic Power Station (AEC and Duquesne Light Co.)[2]	Shippingport, Pa.	West.	Pressurized water	90,000	505,000	1957	
Dresden Nuclear Power Station, Unit 1 (Commonwealth Edison Co.)[3]	Morris, Ill.	GE	Boiling water	200,000	700,000	1959	
Yankee Nuclear Power Station (Yankee Atomic Electric Co.)[3,4]	Rowe, Mass.	West.	Pressurized water	175,000	600,000	1960	
Big Rock Point Nuclear Plant (Consumers Power Co.)[3,4]	Big Rock Point, Mich.	GE	Boiling water	70,300	240,000	1962	
Indian Point Station, Unit 1 (Consolidated Edison Co. of New York, Inc.)[3,5]	Indian Point, N.Y.	B&W	Pressurized water	265,000	615,000	1962	
Enrico Fermi Atomic Power Plant Unit 1 (Power Reactor Development Co.)[3,4]	Lagoona Beach, Mich.	PRDC	Sodium cooled, fast	60,900	200,000	1963	
Humboldt Bay Power Plant, Unit 3 (Pacific Gas & Electric Co.)[3]	Eureka, Calif.	GE	Boiling water	68,500	240,000	1963	
Peach Bottom Atomic Power Station, Unit 1 (Philadelphia Electric Co.)[3,4]	Peach Bottom, Pa.	GGA	Gas cooled, graphite moderated.	40,000	115,000	1966	

TABLE II–6—Continued

Name and/or owner	Location	Principal nuclear contractor	Type	Power[1] Plant, net kW(e)	Power[1] Reactor, kW(t)	Start-up	Shut-down
San Onofre Nuclear Generating Station, Unit 1 (Southern California Edison and San Diego Gas & Electric Co.)[3,4]	San Clemente, Calif.	West.	Pressurized water	430,000	1,347,000	1967	
La Crosse Boiling Water Reactor (AEC and Dairyland Power Cooperative)[3,4]	Genoa, Wis.	AC	Boiling water	50,000	165,000	1967	
Haddam Neck Plant (Connecticut Yankee Atomic Power Co.)[3,4]	Haddam Neck, Conn.	West.	Pressurized water	575,000	1,825,000	1967	
Oyster Creek Nuclear Power Plant, Unit 1 (Jersey Central Power & Light Co.)[3]	Toms River, N.J.	GE	Boiling water	530,000	1,690,000	1969	
Nine Mile Point Nuclear Station (Niagara Mohawk Power Corp.)[3]	Scriba, N.Y.	GE	Boiling water	500,000	1,538,000	1969	
Robert Emmett Ginna Nuclear Power Plant, (Rochester Gas & Electric Co.)[3]	Ontario, N.Y.	West.	Pressurized water	420,000	1,300,000	1969	
Dresden Nuclear Power Station, Unit 2 (Commonwealth Edison Co.)[3]	Morris, Ill.	GE	Boiling water	809,000	2,527,000	1970	
Millstone Nuclear Power Station, Unit 1 (Connecticut Light & Power Co., Hartford Electric Light Co., and Western Massachusetts Electric Co.)[3]	Waterford, Conn.	GE	Boiling water	652,100	2,011,000	1970	
H. B. Robinson S. E. Plant, Unit 2 (Carolina Power & Light Co.)[3]	Hartsville, S.C.	West.	Pressurized water	700,000	2,200,000	1970	
Monticello Nuclear Generating Plant (Northern States Power Co.)[3]	Monticello, Minn.	GE	Boiling water	545,000	1,670,000	1970	
Point Beach Nuclear Plant, Unit 1 (Wisconsin Electric Power Co. and Wisconsin Michigan Power Co.)[3]	Two Creeks, Wis.	West.	Pressurized water	497,000	1,518,000	1970	
Being built:							
Palisades Plant, Unit 1 (Consumers Power Co. of Michigan)[3]	South Haven, Mich.	Comb.	Pressurized water	700,000	2,212,000	1971	
Dresden Nuclear Power Station, Unit 3 (Commonwealth Edison Co.)[3]	Morris, Ill.	GE	Boiling water	809,000	2,527,000	1971	
Oconee Nuclear Station, Unit 1 (Duke Power Co.)[3]	Seneca, S.C.	B&W	Pressurized water	841,120	2,452,000	1971	
Indian Point Station, Unit 2 (Consolidated Edison Co. of New York, Inc.)[3]	Indian Point, N.Y.	West.	Pressurized water	872,890	2,758,000	1971	
Browns Ferry Nuclear Power Plant, Unit 1 (TVA)[3]	Decatur, Ala.	GE	Boiling water	1,064,500	3,293,000	1971	
Peach Bottom Atomic Power Station, Unit 2 (Philadelphia Electric Co., Public Service Electric & Gas Co., Atlantic City Electric Co., Delmarva Power & Light Co.)[3].	Peach Bottom, Pa.	GE	Boiling water	1,065,000	3,294,000	1971	
Quad-Cities Station, Unit 1 (Commonwealth Edison Co. and Iowa-Illinois Gas and Electric Co.)[3].	Cordova, Ill.	GE	Boiling water	809,000	2,511,000	1971	
Surry Power Station, Unit 1 (Virginia Electric & Power Co.)[3].	Gravel Neck, Va.	West.	Pressurized water	780,000	2,441,000	1971	
Zion Station, Unit 1 (Commonwealth Edison Co.)[3].	Zion, Ill.	West.	Pressurized water	1,050,000	3,250,000	1971	
Turkey Point Station, Unit 3 (Florida Power & Light Co.)[3].	Turkey Point, Fla.	West.	Pressurized water	651,500	2,097,000	1971	
Vermont Yankee Generating Station (Vermont Yankee Nuclear Power Corp.)[3].	Vernon, Vt.	GE	Boiling water	513,900	1,593,000	1971	
Quad-Cities Station, Unit 2 (Commonwealth Edison Co. and Iowa-Illinois Gas & Electric Co.)[3].	Cordova, Ill.	GE	Boiling water	809,000	2,511,000	1971	
Pilgrim Station (Boston Edison Co.)[3]	Plymouth, Mass.	GE	Boiling water	655,000	1,998,000	1971	
Point Beach Nuclear Plant, Unit 2 (Wisconsin Electric Power Co. and Wisconsin Michigan Power Co.)[3].	Two Creeks, Wis.	West.	Pressurized water	497,000	1,518,000	1971	
Fort St. Vrain Nuclear Generating Station (Public Service Co. of Colorado)[3,4].	Platteville, Colo.	GGA	Gas cooled, graphite moderated.	330,000	841,700	1971	
Cooper Nuclear Station (Nebraska Public Power District)[3].	Brownville, Nebr.	GE	Boiling water	778,000	2,381,000	1971	
Oconee Nuclear Station, Unit 2 (Duke Power Co.)[3].	Seneca, S.C.	B&W	Pressurized water	886,000	2,568,000	1972	
Three Mile Island Station, Unit 1 (Metropolitan Edison Co.)[3].	Middletown, Pa.	B&W	Pressurized water	810,000	2,452,000	1972	
Fort Calhoun Station, Unit 1 (Omaha Public Power District)[3].	Fort Calhoun, Nebr.	Comb.	Pressurized water	457,400	1,420,000	1972	

TABLE II–6—(Continued)

:Part 1—Civilian reactors (domestic):

Name and/or owner	Location	Principal nuclear con-tractor	Type	Power[1] Plant, net kW(e)	Power[1] Reactor, kW(t)	Start-up	Shut-down
Being built (Continued)							
Surry Power Station, Unit 2 (Virginia Electric & Power Co.)[3].	Gravel Neck, Va.	West.	Pressurized water	780,000	2,441,000	1972	
Salem Nuclear Generating Station, Unit 1 (Public Service Electric & Gas Co., Philadelphia Electric Co., Atlantic City Electric Co., Delmarva Power & Light Co.)[3].	Salem, N.J.	West.	Pressurized water	1,050,000	3,250,000	1972	
Turkey Point Station, Unit 4 (Florida Power & Light Co.)[3].	Turkey Point, Fla.	West.	Pressurized water	651,500	2,097,000	1972	
Diablo Canyon Nuclear Power Plant, Unit 1 (Pacific Gas & Electric Co.)[3].	Diablo Canyon, Calif.	West.	Pressurized water	1,060,000	3,250,000	1972	
Prairie Island Nuclear Generating Plant, Unit 1 (Northern States Power Co.)[3].	Red Wing, Minn.	West.	Pressurized water	530,000	1,650,000	1972	
Maine Yankee Atomic Power Plant (Maine Yankee Atomic Power Corp.)[3].	Wiscasset, Maine	Comb.	Pressurized water	790,000	2,440,000	1972	
Browns Ferry Nuclear Power Plant, Unit 2 (Tennessee Valley Authority)[3].	Decatur, Ala.	GE	Boiling water	1,064,500	3,293,000	1972	
Kewaunee Nuclear Power Plant (Wisconsin Power & Light Co., Wisconsin Public Service Co., Madison Gas & Electric Co.)[3].	Carlton, Wis.	West.	Pressurized water	527,000	1,650,000	1972	
Crystal River Plant, Unit 3 (Florida Power Corp.)[3].	Red Level, Fla.	B&W	Pressurized water	858,000	2,452,000	1972	
Peach Bottom Atomic Power Station, Unit 3 (Philadelphia Electric Co., Public Service Electric & Gas Co., Atlantic City Electric Co., Delmarva Power & Light Co.)[3].	Peach Bottom, Pa.	GE	Boiling water	1,065,000	3,294,000	1972	
Rancho Seco Nuclear Generating Station, Unit 1 (Sacramento Municipal Utility District)[3].	Clay Station, Calif.	B&W	Pressurized water	804,000	2,452,000	1972	
Calvert Cliffs Nuclear Power Plant, Unit 1 (Baltimore Gas & Electric Co.)[3].	Lusby, Md.	Comb.	Pressurized water	800,000	2,450,000	1972	
Edwin I. Hatch Nuclear Plant, Unit 1 (Georgia Power Co.)[3].	Baxley, Ga.	GE	Boiling water	786,000	2,436,000	1972	
Donald C. Cook Nuclear Plant, Unit 1 (Indiana and Michigan Electric Co.)[3].	Bridgman, Mich.	West.	Pressurized water	1,054,000	3,250,000	1972	
Beaver Valley Power Station, Unit 1 (Duquesne Light, Ohio Edison Co., and Pennsylvania Power Co.)[3].	Midland, Pa.	West.	Pressurized water	847,000	2,660,000	1972	
Arkansas Nuclear One, Unit 1 (Arkansas Power & Light Co.)[3].	London, Ark.	B&W	Pressurized water	820,000	2,452,000	1972	
Browns Ferry Nuclear Power Plant, Unit 3 (TVA)[3].	Decatur, Ala.	GE	Boiling water	1,064,500	3,293,000	1973	
Oconee Nuclear Station, Unit 3 (Duke Power Co.)[3].	Seneca, S.C.	B&W	Pressurized water	886,000	2,568,000	1973	
Donald C. Cook Nuclear Plant, Unit 2 (Indiana and Michigan Electric Co.)[3].	Bridgman, Mich.	West.	Pressurized water	1,060,000	3,250,000	1973	
Calvert Cliffs Nuclear Power Plant, Unit 2 (Baltimore Gas & Electric Co.)[3].	Lusby, Md.	Comb.	Pressurized water	800,000	2,450,000	1973	
Zion Station, Unit 2 (Commonwealth Edison Co.)[3].	Zion, Ill.	West.	Pressurized water	1,050,000	3,250,000	1973	
Indian Point Station, Unit 3 (Consolidated Edison Co. of New York, Inc.)[3].	Indian Point, N.Y.	West.	Pressurized water	965,000	3,025,000	1973	
Salem Nuclear Generating Station, Unit 2 (Public Service Electric & Gas Co., (Philadelphia Electric Co.)[3].	Salem, N.J.	West.	Pressurized water	1,050,000	3,250,000	1973	
Three Mile Island Nuclear Station, Unit 2 (Jersey Central Power & Light Co.)[3].	Middletown, Pa.	B&W	Pressurized water	810,000	2,452,000	1974	
Brunswick Steam Electric Plant, Unit 2 (Carolina Power & Light Co.)[3].	Southport, N.C.	GE	Boiling water	821,000	2,436,000	1973	
Sequoyah Nuclear Power Plant, Unit 1 (Tennessee Valley Authority)[3].	Daisy, Tenn.	West.	Pressurized water	1,124,000	3,423,000	1973	
Duane Arnold Energy Center, Unit 1 (Iowa Electric Light & Power Co., Central Iowa Power Cooperative and Corn Belt Power Cooperative)[3].	Palo, Iowa	GE	Boiling water	545,000	1,593,000	1973	
James A. FitzPatrick Nuclear Power Plant (Power Authority of the State of New York)[3].	Scriba, N.Y.	GE	Boiling water	821,000	2,436,000	1973	

TABLE II-6—(Continued)

[Part 1—Civilian reactors (domestic)]

Name and/or owner	Location	Principal nuclear contractor	Type	Power[1] Plant, net kW(e)	Power[1] Reactor, kW(t)	Start-up	Shut-down
Hutchinson Island, Unit 1 (Florida Power & Light Co.)[3].	Fort Pierce, Fla	Comb.	Pressurized water	813,000	2,440,000	1973	
Millstone Nuclear Power Station, Unit 2 (Connecticut Light & Power Co., Hartford Electric Light Co. and Western Massachusetts Electric Co.)[3].	Waterford, Conn	Comb.	Pressurized water	828,000	2,560,000	1973	
Diablo Canyon Nuclear Power Plant, Unit 2 (Pacific Gas & Electric Co.)[3].	Diablo Canyon, Calif.	West.	Pressurized water	1,060,000	3,250,000	1973	
Sequoyah Nuclear Power Plant, Unit 2 (Tennessee Valley Authority)[3].	Daisy, Tenn	West.	Pressurized water	1,124,000	3,423,000	1974	
Prairie Island Nuclear Generating Plant, Unit 2 (Northern States Power Co.)[3].	Red Wing, Minn	West.	Pressurized water	530,000	1,650,000	1974	
Brunswick Steam Electric Plant, Unit 1 (Carolina Power & Light Co.)[3].	Southport, N.C	GE	Boiling water	821,000	2,436,000	1975	
Planned:							
North Anna Power Station, Unit 1 (Virginia Electric & Power Co.)[3].	Mineral, Va	West.	Pressurized water	845,000	2,652,000	1973	
Enrico Fermi Atomic Power Plant, Unit 2 (Detroit Edison Co.)[3].	Lagoona Beach, Mich.	GE	Boiling water	1,123,000	3,293,000	1973	
Trojan Nuclear Plant, Unit 1 (Portland General Electric Co., Eugene Water & Electric Board and Pacific Power & Light Co.)[3].	Rainier, Oreg	West.	Pressurized water	1,130,000	3,423,000	1974	
Davis-Besse Nuclear Power Station (Toledo Edison Co. and Cleveland Electric Illuminating Co.)[3].	Oak Harbor, Ohio	B&W	Pressurized water	872,000	2,650,000	1974	
Joseph M. Farley Nuclear Plant, Unit 1 (Alabama Power Co.)[3].	Dothan, Ala	West.	Pressurized water	829,000	2,652,000	1974	
North Anna Power Station, Unit 2 (Virginia Electric & Power Co.)[3].	Mineral, Va	West.	Pressurized water	845,000	2,652,000	1974	
Newbold Island Nuclear Generating Station, Unit 1 (Public Service Electric & Gas Co.)[3].	Newbold Island, N.J.	GE	Boiling water	1,088,000	3,293,000	1974	
Limerick Generating Station, Unit 1 (Philadelphia Electric Co.)[3].	Pottstown, Pa	GE	Boiling water	1,065,000	3,294,000	1974	
William H. Zimmer Nuclear Power Station, Unit 1 (Cincinnati Gas & Electric Co., Columbus & Southern Ohio Electric Co., and Dayton Power & Light Co.)[3].	Moscow, Ohio	GE	Boiling water	810,000	2,436,000	1974	
Shoreham Nuclear Power Station (Long Island Lighting Co.)[3]	Brookhaven, N.Y	GE	Boiling water	819,000	2,436,000	1975	
William B. McGuire Nuclear Station, Unit 1 (Duke Power Co.)	Cowans Ford Dam, N.C.	West.	Pressurized water	1,150,000	3,423,000	1975	
Forked River Nuclear Generating Station, Unit 1 (Jersey Central Power & Light Co.)	Forked River, N.J	Comb.	Pressurized water	1,140,000	3,390,000	1975	
San Onofre Nuclear Generating Station, Unit 2 (Southern California Edison Co., and San Diego Gas & Electric Co.)[3].	San Clemente, Calif.	Comb.	Pressurized water	1,140,000	3,410,000	1975	
Edwin I. Hatch Nuclear Plant, Unit 2 (Georgia Power Co.).	Baxley, Ga	GE	Boiling water	786,000	2,436,000	1975	
Aguirre Nuclear Power Plant (Puerto Rico Water Resources Authority).	Puerto Rico	West.	Pressurized water	583,000	1,785,000	1975	
Arkansas Nuclear One, Unit 2 (Arkansas Power & Light Co.).	London, Ark	Comb.	Pressurized water	950,000	2,452,000	1975	
LaSalle County Nuclear Station, Unit 1 (Commonwealth Edison Co.)	Seneca, Ill	GE	Boiling water	1,078,000	3,293,000	1975	
Bailly Generating Station (Northern Indiana Public Service Co.).	Dunes Acres, Ind	GE	Boiling water	660,000	1,931,000	1976	
Carolina Power & Light Co.	North Carolina	GE	Boiling water	821,000		1976	
Newbold Island Nuclear Generating Station, Unit 2 (Public Service Electric & Gas Co.)[3].	Newbold Island, N.J.	GE	Boiling water	1,088,000	3,293,000	1976	
Limerick Generating Station, Unit 2 (Philadelphia Electric Co.)[3].	Pottstown, Pa	GE	Boiling water	1,065,000	3,294,000	1976	
San Onofre Nuclear Generating Station, Unit 3 (Southern California Edison Co., and San Diego Gas & Electric Co.)[3].	San Clemente, Calif.	Comb.	Pressurized water	1,140,000	3,410,000	1977	

TABLE II–6—Continued

Name and/or owner	Location	Principal nuclear contractor	Type	Power[1] Plant, net kW(e)	Power[1] Reactor, kW(t)	Start-up	Shut-down
LaSalle County Nuclear Station, Unit 2 (Commonwealth Edison Co.).	Seneca, Ill.	GE	Boiling water	1,100,000		1977	
Bell Station (New York State Gas & Electric Co.)[6].	Lansing, N.Y.	GE	Boiling water	838,000	2,436,000		
William B. McGuire Nuclear Station, Unit 2 (Duke Power Co.).	Cowans Ford Dam, N.C.	West.	Pressurized water	1,150,000	3,423,000	1976	
Watts Bar Nuclear Plant, Unit 1 (Tennessee Valley Authority).		West.	Pressurized water	1,170,000		1976	
Watts Bar Nuclear Plant, Unit 2 (Tennessee Valley Authority).		West.	Pressurized water	1,170,000		1976	
Waterford Generating Station, Unit 3 (Louisiana Power & Light Co.).	Taft, La.	Comb.	Pressurized water	1,165,000		1976	
Tennessee Valley Authority, Unit 1		B&W	Pressurized water	1,201,000		1977	
Tennessee Valley Authority, Unit 2		B&W	Pressurized water	1,201,000		1977	
(Consolidated Edison Co.)[3], Verplanck No. 1	Verplanck, N.Y.	GE	Boiling water	1,115,000	3,293,000	1977	
Joseph M. Farley Nuclear Plant, Unit 2	Dothen, Ala.	West.	Pressurized water	829,000		1977	
(Pennsylvania Power & Light Co.), Susquehanna Steam Electric Station, Unit 1	Berwick, Pa.	GE	Boiling water	1,052,000	3,293,000	1978	
(Pennsylvania Power & Light Co.), Susquehanna Steam Electric Station, Unit 2	Berwick, Pa.	GE	Boiling water	1,052,000	3,293,000	1979	
Shut down or dismantled:							
Hallam Nuclear Power Facility, Sheldon Station (AEC and Consumers Public Power District[4,7].	Hallam, Nebr.	AI	Sodium graphite	75,000	256,000	1962	1964
Carolinas-Virginia Tube Reactor (Carolinas-Virginia Nuclear Power Associates, Inc.)[3,4,8].	Parr, S.C.	West.	Pressure tube, heavy water.	17,000	65,000	1963	1967
Piqua Nuclear Power Facility (AEC and City of Piqua)[3,4].	Piqua, Ohio	AI	Organic cooled and moderated.	11,400	45,500	1963	1967
Boiling Nuclear Superheater Power Station (AEC and Puerto Rico Water Resources Authority)[3,4].	Punta Higuera, P.R.	Comb.	Boiling water integral nuclear superheat.	16,500	50,000	1964	1968
Pathfinder Atomic Power Plant (Northern States Power Co.)[3,4,9].	Sious Falls, S. Dak.	AC	Boiling water, nuclear superheat.	58,500	190,000	1964	1968
Elk River Reactor (AEC and Rural Cooperative Power Association)[3,4,10].	Elk River, Minn.	AC	Boiling water	22,000	58,200	1962	1970
B. DUAL-PURPOSE PLANTS							
Operable:							
N Reactor (AEC and Washington Public Power Supply System)[11].	Richland, Wash.	DUN	Graphite	790,000	4,000,000	1963	
Planned:							
Midland Nuclear Power Plant, Unit 1 (Consumers Power Co. of Michigan)[3,12].	Midland, Mich.	B&W	Pressurized water	492,000	2,468,000	1974	
Midland Nuclear Power Plant, Unit 2 (Consumers Power Co. of Michigan)[3,12].	Midland, Mich.	B&W	Pressurized water	818,000	2,468,000	1975	

[1] Power-capacity figures are based on the best available information. In all instances thermal capacity of the nuclear reactor is given; the electrical output, when shown, is the net electrical capacity of the power plant. For reactors being built or planned, plant capacity is rounded to the nearert hundred kilowatts. Where a plant has a stretch capacity, the initial capacity is given until the stretch value is approved.

[2] The Shippingport station is provided with a turbogenerator rated at 90,000 kW(e) net. Use of a heat-dissipation system permits operation at 150,000 kW(e) gross equivalent on core 2. Power operation with core 2 began Apr. 30, 1965.

[3] This facility is regulated by the AEC Director of Regulation and has been issued an operating license (or authorization) or a construction permit, or an application for same has been submitted.

[4] This project is under the Power Demonstration Program.

[5] In the Consolidated Edison Indian Point Station, the 615,000 kW(t) is increased by an oil-fired superheater to produce 265,000 net kW(e).

[6] New York State Electric and Gas Corp. on Apr. 11, 1969, announced indefinite postponement of the Bell Station.

[7] The Hallam Nuclear Power Facility was shut down in September 1964 due to moderator-can failures. In August 1965 the Commission terminated its contract with Consumers Public Power District for operation of the nuclear plant. In May 1966 CPPD turned down their option to purchase the plant. In June 1966 the AEC announced deactivation and dismantling of the nuclear facility.

[8] The last CVTR shutdown occurred Jan. 24, 1967. A license amendment issued June 14, 1967, authorizes CVNPA to possess but not operate the CVTR.

[9] The Pathfinder Plant has been shut down since November 1967. On Sept. 9, 1968, Northern States Power Company announced plans to install gas-fired boilers for operation the summer of 1969.

[10] The 58,200-kW(t) capacity of the Elk River Reactor is increased to 73,000 kW(t) by a fossil-fired superheater to produce 22,000 net kW(e). Thermal capacity of the reactor is equivalent to about 16,000 kW(e); the 14,800 kW(t) from the superheater is equivalent to about 6000 kW(e). Plant was shut down due to technical problems in February 1968; on Mar. 20, 1970, RCPA rejected an option to purchase ERR.

[11] N Reactor, an AEC-owned reactor for production of special nuclear materials, also produces steam that is supplied to the adjacent electric generating plant, owned and operated by Washington Public Power Supply System (WPPSS). Initial electric-power generation began Apr. 8, 1966. Full gross power output of 800 MW(e) utilizing N Reactor steam was achieved on Dec. 9, 1966.

[12] Midland Unit 1 supplies 3,625,000 pounds per hour of process steam, and Unit 2 supplies 425,000 pounds per hour.

in operation today are of the thermal type, but considerable effort is being exerted to develop an economically attractive commercial fast reactor system. The interest in fast reactors is due to their capability for utilizing a much larger portion of the potential energy available in fertile materials than do the thermal reactors.

Reactor systems are further classified as "breeders" and "converters" according to the amount of fertile material, such as uranium 238 and thorium 232, which is converted to fissile material, namely plutonium 239 and uranium 233, within the reactor. Where more new fuel is produced than is consumed, the reactor is called a breeder, while the converter system produces less fissile material, in varying degrees, than is consumed. Reactor systems with high conversion and breeding ratios should have lowered fuel cycle costs, and would conserve the available supplies of fissile material. While thermal reactor systems can be designed to breed or have high conversion ratios, the fast reactor system has the edge in this regard.

A listing of all operating and planned central station power reactors in the U.S., as of December 31, 1970, is contained in Table II–6. While manufacturers' publications, textbooks, and the technical press include in-depth discussions of the various reactor systems of interest today, a very brief description of these systems is given below.

Reactor Systems in Commercial Operation in the U.S. Today

1. *Pressurized Water Reactor* (*PWR*)

In the PWR system, water at high pressure (~2,000 psi) serves as both moderator and coolant and is pumped through the reactor core where heat from the fuel elements is absorbed. The heated water is then used to produce saturated or slightly superheated steam in a separate heat exchanger. Since radioactivity is confined to the primary system, the turbine and steam system are not radioactive. Net plant thermal efficiencies of up to about 35 percent are obtained. Systems using light water are of primary interest in the United States. Heavy water systems have been utilized in Canada.

Fuel in present-day commercial PWR's is in the form of slightly enriched (~ three percent) uranium dioxide pellets about 0.4″ diameter in tubing fabricated from a zirconium alloy. The fuel rods or tubes are assembled on a square pitch into a rod bundle of about 12 to 14 foot length. Control rods replace some of the fuel tubes in selected bundles. Further control is achieved through the use of boric acid, which, when added to the primary water, enables PWR's to be operated with better power distribution in the core. However, if a PWR is shut down from this condition, a delay in startup may be involved while the boric acid is removed from the primary water.

Redundant systems for heat removal from the core are provided as engineered safeguards against the extremely remote possibility of complete loss of water from the primary system.

2. *Boiling Water Reactor* (*BWR*)

In the BWR, steam is generated at a pressure of approximately 1,000 psi as water is circulated through the reactor core. Steam separators and dryers are located within the reactor vessel, and the saturated steam is piped directly to the turbo-generator. Some radioactivity will be present in the steam, and some shielding of the turbine and heat cycle components is normally required. Net plant thermal efficiencies of approximately 34 percent are obtained.

Fuel elements are similar to those of the PWR although fewer fuel rods of slightly larger diameter are contained in each fuel bundle, and the enrichment of about 2.5 percent is slightly lower. A cruciform shaped control rod containing boron is provided for, and is inserted between each group of four fuel bundles. Power output of the reactor is regulated by both movement of control rods, and changes in recirculation flow rate through the core.

BWR's require more fuel in the initial core than PWR's; however, in the long run, both types consume about the same amount of fuel.

3. *High Temperature Gas-Cooled Reactor* (*HTGR*)

The HTGR is a graphite-moderated, thermal reactor concept cooled with helium. Helium leaving the reactor at a temperature of 1,400° F passes to steam generators where high pressure steam at a temperature of 1,000° F is produced. A reheat steam cycle may also be utilized which would result in a cycle efficiency similar to that of modern fossil plants. The heat dissipation requirements to the environment would thus be less than for similarly sized light water nuclear plants. Net plant thermal efficiencies of about 40 percent are obtained.

Because of the prospects for better uranium utilization and higher efficiency, it is expected that the HTGR could, when fully developed and commercially accepted, produce electricity more cheaply than light water reactors. However, because of limited production and experience, the

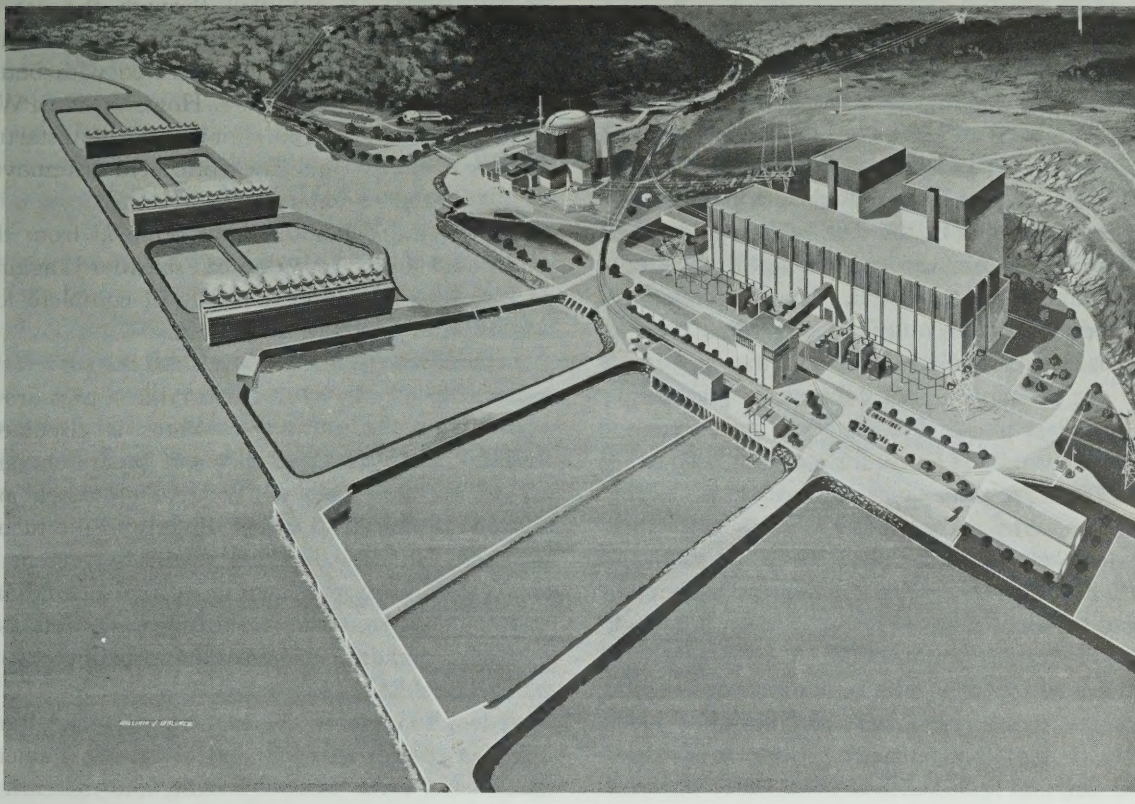


FIGURE 17.—Artist's conception of Philadelphia Electric Company's Peach Bottom Atomic Power Station. Operating Unit No. 1–40 mw (HTGR) on left, Units 2 and 3–1,065 mw (BWR) each scheduled for operation in 1973 and 1974 on the right.

HTGR has not reached the levels of technical development and commercial acceptance which have been achieved by light water reactors. In the United States, a 40-mw HTGR, the Peach Bottom Atomic Power Station, Unit 1, is operating; construction is underway on a 330-mw HTGR, the Fort St. Vrain Nuclear Generating Station. Small HTGR's have been built in England and in West Germany. A 300-mw HTGR, the Thorium High Temperature Reactor (THTR), is being built in Germany.

The fuel used in HTGR's in the United States is in the form of highly enriched (90 percent) uranium dioxide or uranium dicarbide microspheres covered with coatings of carbon. The fertile material is coated thorium particles in the form of dioxide or dicarbide microspheres. Plutonium fuels could also be used in the HTGR. The Ft. St. Vrain core will be built of graphite prismatic columns having holes to contain the fuel and fertile particles, to permit the helium coolant to pass through the columns, and to allow insertion of the control rods.

The HTGR is inherently stable. While the design achieves a negative temperature coefficient, it is necessary to insert control rods or some other form of neutron absorber to shut down the reactor.

Advanced Concepts

1. *Advanced Converters*

An advanced converter reactor may be defined as one which has a conversion ratio that approaches 1, much higher than present-day light water reactors. The problem involved in advanced converter development is that, while they improve uranium ore utilization, it is difficult to justify the investment which is necessary for a developmental program. At the present time, the only two advanced converter reactors which may be said to be under development are the previously described HTGR and various versions of the heavy water pressure tube reactor.

In this latter concept, pressure tubes pass through a calandria containing heavy water. The pressure tubes contain the fuel elements which may be cooled with gas, pressurized or boiling light water, or an organic fluid at relatively high pressure while the heavy water in the low pressure tank or calandria is maintained at near atmospheric pres-

sure. The neutron economy of the heavy water moderator permits the use of natural uranium fuel although uranium of low enrichment or plutonium may also be used. The 250-mw Heavy-Water-Boiling Light Water Reactor under construction in Canada will be fueled with natural uranium; the 100-mw Steam Generating Heavy Water Reactor is operating in England using slightly enriched uranium. If uranium ore becomes a great deal more expensive than it is at present, it may be economical to introduce thorium into the heavy water pressure tube reactor. It is of interest to note that in Canada there are presently under construction two heavy water nuclear plants, Pickering and Bruce, each to consist eventually of four units totalling 2000 MWe and 3000 MWe respectively.

2. *Thermal Breeder Reactors*

It has been shown that it is not possible, in practical thermal reactors, to breed using the plutonium-uranium fuel cycle. However, it is generally agreed that the number of neutrons produced per atom fissioned is sufficient to permit breeding in thermal thorium reactors which are well moderated with light water, heavy water, graphite or beryllium, and fueled with uranium 233. The margin for breeding is small, and great care must be exercised to conserve neutrons. Two thermal breeder reactor concepts are under development in the United States; these are the Molten Salt Breeder Reactor and the Light Water Breeder Reactor.

Molten Salt Breeder Reactor (*MSBR*).—This concept is a circulating fuel reactor in which the fuel-carrying fluid passes through a graphite core structure where criticality is achieved, and heat is generated. The fluid then passes out of the core, becoming sub-critical, and then passes through a heat exchanger where heat is transferred to a secondary fluid. The fuel would be in the form of uranium tetrafluoride, and the carrier salt would be a mixture of the fluorides of lithium and beryllium melting at about 850° F. The fertile material would be in the form of thorium tetrafluoride, and may be carried in a separate salt in a two-fluid reactor, or carried in the same salt with the fuel in a single fluid reactor.

A side stream of the fuel bearing salt would be processed continuously to remove neutron-absorbing fission products. The primary salt and any part of the system which comes into contact with it would be intensely radioactive. A secondary salt which removes heat from the primary salt and which might be sodium fluoborate, would not contain fission products. The breeding ratio of the MSBR would be low, compared to a LMFBR, probably about 1.05; however, the doubling time might be comparable to that of an LMFBR due to its lower fissile fuel inventory. In spite of its circulating fuel system, it is predicted that an MSBR would have a fissile inventory considerably smaller than an LMFBR and present-day light water reactors (LWR).

Because of the low inventory charges and absence of fuel fabrication charges, it is predicted that an MSBR would have a very low fuel cost.

Light Water Breeder Reactor.—This is a pressurized water reactor currently being developed which operates on the thorium-uranium 233 fuel cycle. Initially, the fissile material would be U-235, which would be later replaced by U-233 after this material is produced in sufficient quantity.

Fast Breeder Reactors

1. *Liquid Metal Fast Breeder Reactor* (*LMFBR*)

The USAEC has chosen the Liquid Metal Fast Breeder Reactor as its highest priority civilian breeder reactor development program; the same choice has been made by most countries having significant reactor development programs. The sodium coolant circulating through the core will leave the reactor at a temperature of about 1,100° F. Heat will be transferred from the primary sodium which is extremely radioactive to a non-radioactive secondary sodium system which in turn heats steam for the turbine in additional heat exchangers. A net plant thermal efficiency of 40 percent can be achieved.

Breeding ratios of about 1.4 are predicted. Because it produces more fissile material than it consumes, a self-sustaining breeder fuel cycle can be based on the use of recycled Pu with U-238 added as the fertile material. Since its new fuel material requirements are relatively small, it can economically utilize low-grade ores. The rate at which fast breeder reactors can be introduced may be limited by the production of plutonium from light water reactors and breeders, although such a situation is not anticipated. The alternative would be to start up some breeders on U-235 fuel, although this material is inferior to plutonium as a fast reactor fuel.

Although it is predicted that the LMFBR will have plant capital costs which are higher than those of light water reactors, the cost of power from the LMFBR should be lower because of the much-improved fuel utilization. Fuel for the first LMFBR's is expected to be mixed plutonium and

uranium dioxides, probably in the form of pellets, encased in stainless steel tubing of smaller diameter than that of the fuel pins for light water reactors. The active core of the breeder reactor will be surrounded on all sides by a blanket region composed of bundles of rods containing depleted uranium from enrichment plant tailings, or uranium from fuel reprocessing plants, or, eventually natural uranium. Neutrons escaping from the active core will be absorbed in the depleted uranium thereby producing plutonium. The technical feasibility of sodium-cooled fast reactors has been demonstrated, but much work remains to develop a satisfactory fuel element.

Major efforts are required before the LMFBR can become a competitive energy source for the utility industry. Still necessary is development of a proven technology that will form the basis for the design of plants of high safety, reliability, and availability, and which also promise good economy. These developments should be achieved within a time span that will bring the first commercially feasible plants into operation in the 1980's.

2. *Gas-Cooled Fast Breeder Reactor* (*GCFR*)

Cooling of large fast reactors with helium has the advantage that loss of the coolant causes only a small reactivity increase. However, helium has only a small capacity, as compared to sodium, for absorbing heat in the event of loss of pumping. Gas-cooled fast reactors should be able to achieve substantially higher breeding ratios than sodium-cooled reactors. However, heat transfer limitations tend to increase fuel inventory so that doubling time of a gas-cooled fast reactor might be about the same as that of an LMFBR.

The GCFR design is based on having its fuel and fertile materials in bundles of rods with a high nickel alloy cladding. A prestressed concrete reactor vessel would be employed with a reactor pressure of about 100 atm. Gas temperature out of the reactor would be about 1,100° F, permitting use of modern reheat turbines. This concept is under active study by one reactor manufacturer in the U.S., supported by a number of electric utilities.

The Closed-Cycle Gas-Cooled Reactor.—All the reactor systems which have been described thus far use steam as the working medium in the turbine cycle; although it is the most common thermodynamic fluid, it is not necessarily the best for all systems. An alternative to the direct or indirect steam cycle nuclear plant is a closed-cycle gas-cooled reactor which omits the steam generator and steam system, and uses the hot gas from the reactor to drive a gas turbine. Such a system might have a lower capital cost due to the simpler plant and a high thermal efficiency.

A gas turbine could be combined with any gas-cooled reactor; however, relatively high gas temperatures are required to obtain good turbine efficiencies. High reactor pressures ($\sim$100 atm) may also be required in large plants to minimize the size of components, and to minimize pumping power. Outlet gas temperatures in excess of 1,400° F are attainable in the HTGR.

Operation

Unit Loading

The use of the nuclear power plant in conjunction with other forms of generation in order to provide energy to meet the daily requirements of a power system will probably not be vastly different from the use of a fossil-fueled plant of the same capacity. There are some differences, however, that may affect the operation of the nuclear plant, such as relative operating costs, refueling time, inspections, load following characteristics, and cyclic operations.

Because an economic loading schedule for a power system will tend to favor operation of units with the lowest incremental production cost, the capacity factor of a nuclear fueled plant is expected to be relatively high when it is added to a system consisting of fossil-fueled plants. However, when newer, more efficient nuclear plants are added to the system, which can operate with even lower production costs, the first nuclear plants will begin to have decreasing capacity factors. Most of the plants that have been ordered during the past three years will probably have annual capacity factors of 80 percent or better for a period of ten to fifteen years, depending on the operating requirements and makeup of the system. The acceptance of the breeder reactor will introduce another factor in the economic evaluation of light water reactor operation as the water reactors produce the plutonium utilized so efficiently by the breeder. Ultimately, however, the water reactors may become the marginal operating plants on a utility's system.

The limited operating experience to date with the comparatively small nuclear plants indicates that they are able to handle load swings without difficulty. It is expected that the larger units now on order will perform similarly, but it may develop that they will not be amenable to load regulation. In that event, fossil units, pumped-storage units, conventional hydro units, or other types of peaking units will be installed to carry peak load with

TABLE II–7

Commercial U.S. Nuclear Reactor Availability Factors*

	Availability factor, percent									
	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969
Dresden	62	40	81	81	83	83	97	60	67	67
Yankee		87	68	79	91	76	90	92	88	83
Indian Point			61	71	48	64	68	81	92	93
Big Rock Point				48	43	30	75	90	81	92
Shippingport	67	80	88	89			96	97	99	77
Humboldt Bay				83	89	80	89	91	93	90
San Onofre								63	44	79
Connecticut Yankee								81	91	94

* Availability factor = percent of year reactor was available to produce power.

nuclear units being maintained at base load for substantially all of their useful lives. If nuclear units are to be utilized with very low annual capacity factors, substantial research and engineering effort must go into the determination of core designs to economically accomplish this type of operation.

Advanced reactor concepts now in the design and development stage will have steam conditions similar to those now encountered in fossil-fired plants. When these nuclear steam supply systems are placed in service, the higher steam temperatures may introduce some limitations on the rate and magnitude of load changes.

Availability

Unit availability is a key factor in operating costs, particularly for large plants. A unit out of service may cost a utility many dollars per hour for replacement energy alone. For a 1,000 mw unit and a one mill advantage in operating cost over the old unit displaced, this would amount to $1,000 per hour. Thus, it is not surprising that a utility makes every effort to minimize outages.

When purchasing new generating facilities, particularly close scrutiny is given to the subject of probable unit down time. This close scrutiny by purchasers is providing sufficient incentive to the manufacturers for the investment of extensive design work to increase availability in every possible manner.

Table II–7 lists the availability by years of the operable PWR and BWR nuclear plants in the U.S. which were placed in commercial operation prior to December 1969. Most of these nuclear plants have required long outages for refueling, frequently several months in duration. However, the length of these outages has been generally decreasing since initial operation. This decrease can be attributed to increased experience in refueling techniques, improved fuel design, better tools, more reliable peripheral equipment and material, and improved access to core internals. Plants now under construction have been designed to reduce refueling down time even more. Estimates of refueling outages for these units are now ranging from one to two months in length. Only a fraction of this total is occupied by fuel handling with the major portions taken up by obtaining and securing access to the core, testing, maintenance, and inspections. As the utilities and the equipment designers gain more and more experience in the refueling process, there is every reason to expect refueling outage time to continue to decrease.

Nonavailability as a result of maintenance has also been quite high on existing nuclear plants. The major reason lies with the lack of experience with new materials and methods, equipment developmental problems, and the one-of-a-kind plant designs, with extreme differences between plants. The plants now in the contract and early construction stages are being standardized as much as possible in equipment and material design. However, these plants represent large extrapolations in capacity and size of systems and components. This may result in new maintenance problems. However, availability should be improved as problem areas are eliminated. The overall trend of maintenance down time in future years is expected to be continually decreasing as the manufacturers and operators gain more experience.

Equipment inspection and material surveillance do not now represent a major portion of plant down time. However, as refueling and maintenance

times decrease, inspection and surveillance may account for a very significant percentage of the total time out of service unless designs and procedures are developed to accomplish effective and rapid inspection. This factor alone is sufficient justification for efforts to reduce the time required for this purpose. The regulatory agencies are placing increasing emphasis here, and probably, new regulations will require increased outage time for several years. Major expenditures of money, engineering work, and time will be required before the trend of increasing inspection time is reversed.

Performance During System Disturbance

1. *Subnormal Frequency*

The design of both nuclear and fossil power plants today does not make special provision for continuous low frequency operation of plant components. However, with nuclear units, an integrated control system is often provided which together with necessary steam bypass facilities allows the unit to be brought from full load to house load, keeping the core output power within limits and permitting the unit to be ready to resume system demand in a much shorter period of time than a large fossil unit.

2. *Auxiliary Power Provision*

Significant attention has been given to safety systems of all licensed nuclear power plants. Units must hold load as long as possible under abnormal conditions to avoid complete system shutdown. When the unit can no longer serve system load requirements without creating further upset, provisions are made for quick and safe shutdowns. Core decay heat is removed by various methods with power supplied from on-site generation or other emergency sources. The on-site plant power system normally used today consists of an independent, automatically started emergency power source which supplies power to essential auxiliaries if normal power is not available. This consists usually of diesel units sized to operate all equipment essential to the safe shutdown of the reactor. A typical array of on-site generation required for a 1,000 mw nuclear power plant is two diesel generators of about 2,500 kw capacity each, with either one capable of supplying enough electric power for a safe shutdown of the reactor.

Computer Applications to Plant Operation

On-line process computers are assuming an increasing role in nuclear applications, and are presently in use for data logging and reduction in nuclear plants and experimental facilities. The computer is also being developed to act as a nuclear training simulator for reactor operators. Because of the number and complexity of measured and calculated parameters during reactor operation, a rapid and complete assessment of the status of the nuclear plant becomes nearly impossible without help from a computer. Larger and more rapid digital computers are being selected by reactor suppliers for such operational aids as sequence of event recording, event recall, instrument calibration, and fuel, control blade, and ion chamber burnup accounting, enabling a reduction in operational uncertainty and permitting reduced core size. To have the computer initiate direct digital control will require improvements in hardware design and numerical reliability.

Applications beyond off-line, open loop control still remain a matter of speculation for the future; however, as "learning" progresses along with better quality control, measurement accuracy and control reliability, the use of computer-direct control will increase, particularly with increased confidence in engineered safeguards by the AEC and owners.

Personnel Requirements

At present, 55 to 65 total plant personnel are required for a single unit nuclear plant, and 80 to 90 people for a two-unit nuclear plant. It is expected that these personnel requirements will decrease slightly in the future. The size of nuclear units will have little effect on either the number of plant people required or on the plant's operating organization.

It is estimated that the aggregate personnel requirement for U.S. central station nuclear plants will rise at a uniform rate, from about 2,100 people in 1970 to over 19,000 people in 1990. These figures cover only the normal plant complement, and do not include those additional maintenance people needed for major outages. The composition of this work force will be about 13 percent plant management and engineers, 13 percent technicians (instrumentation, health physics and plant chemistry), 17 percent plant services personnel, 37 percent operating people, and 20 percent maintenance people. On a yearly basis, the number of new positions created by the growth of nuclear plants will rise to approximately 850 per year in 1975, and will remain reasonably constant at this value through 1990. Furthermore, as nuclear generation becomes an important segment of a utility's total generating capacity, each utility will require 30 to

40 additional nuclear oriented headquarters personnel. The colleges and universities are responding to the need for increasing number of professional people skilled in the nuclear fields, and are initiating the required undergraduate and graduate programs.

The additional personnel required for the nuclear units will be supplied in part by utilizing existing utility employees, and in part by hiring new employees. In either case, extensive training programs will be needed to prepare the men for their job assignments.

Training of Personnel

It is essential that utility employees obtain early training in order to become acquainted with the technological advances, meet licensing requirements, and obtain sound attitudes toward nuclear safety.

Training for both management and headquarters personnel is generally carried out on a part-time basis through enrollment in nuclear seminars. Such programs will vary in scope but may involve university graduate level courses given either on the campus or at the utilities' headquarters. Attendance at programs initiated by industrial organizations or the AEC supplement the theoretical training of the formalized courses. Many consulting organizations are available to assist utility management in planning for and in conducting a well-rounded training program. The training of management personnel should be initiated some time before bids are placed for nuclear units.

The training of technical personnel for supervisory positions in the plant must be more stringent than for headquarters personnel and must include operating experience at existing nuclear plants. The lead time for nuclear units provides sufficient time for such training if full-time assignments are made beginning with the decision to construct a nuclear plant. As additional nuclear units are ordered for a utility's system, men may be drawn from the trained cadre which has been developed for previous units.

The initial step in the training program for the plant staff is to obtain a firm understanding of nuclear theory through formalized class and laboratory courses. This is followed by operating experience at a reactor which may be gained at an existing facility, and supplemented by working with a university or pool type reactor. Programs conducted by the manufacturer of the purchased reactor system will then enable the supervisor to become familiar with the technology and features of his plant. Many universities are willing and able to arrange theoretical and practical training programs which, together with those available from the manufacturer, provide a foundation for understanding and coping with the problems that will arise in the future operation of the plant. At the conclusion of the training program, application may be made for an AEC license at the facility at which the reactor operating experience was obtained. A satisfactory grade in the licensing examination is a prerequisite for consideration to be examined for a license on the new facility which the applicant's employer is constructing. At this point in time the new plant will be under construction, and the plant staff will begin the development of training manuals and operating procedures. The remainder of the operating organization will also have been selected, and will have begun the training program organized for them by the plant staff.

The training for plant operating personnel will begin about 18 months to two years prior to the scheduled date for fuel loading. The first phase of the training program will primarily be classroom study conducted by either the manufacturer, a university, or company personnel. The subjects covered in the program will include a review of mathematics and an introduction to reactor theory and nuclear physics, plant chemistry, health physics, plant instrumentation and nuclear systems. The second phase of the program consists of on-the-job training at a nuclear facility or simulator supplemented by classroom study. The operators will then assist in the development of plant operating procedures, perform preoperational tests of the plant's systems, and prepare for the AEC licensing examinations.

The AEC issues two grades of license, Operator and Senior Operator. The regulations state that a licensed Operator must be at the controls of the reactor, and the Technical Specifications generally require that a Senior Operator be present at the facility at all times. It is estimated that during the early 1970's over 300 people per year will require AEC operating licenses, and by 1990, the number will increase to about 400 people per year. These figures do not include renewal applications. The prerequisite training requirements for this many people represent a significant expenditure of time, effort, and money. At the present time, utilities are relying on the manufacturers for a large part of the training effort, but as additional nuclear units are installed on a utility's system the emphasis will shift.

The nuclear power plant simulator is currently emerging as a training tool which will assume greater importance in the future. A well-designed simulator contains the necessary active instrumentation and equipment to permit start-up and loading of the plant to full power from both the hot and cold shutdown condition. It also provides accurate responses to changes in system pressure, temperature and flow and to control rod position, and enables the simulation of many malfunctions and equipment failures. When these facts are combined with the economic penalty for utilizing a larger power reactor for start-up and shutdown training, it is readily appreciated that the simulator provides a superior training means. It is envisioned in the future that nuclear plant simulators will be shared by several plants or utilities, perhaps through mobilizing the computer and mock-up control rooms so that they may be transported to the plant sites. It is also anticipated that greater emphasis will be placed on video tapes and other teaching aids for the training and retraining of operating and maintenance personnel.

It is currently estimated that a utility spends over one million dollars in training costs to prepare personnel to man a nuclear plant. It is expected that this cost will gradually decrease as more experienced personnel become available.

Retirement Aspects

The removal of a nuclear power plant from service will, without doubt, be much more complicated than the retirement of a fossil-fueled plant. However, the decommissioning or retirement of nuclear units do not introduce any significantly new or unknown safety problems. The AEC's experience in decommissioning its reactors shows that this can be done safely, although not inexpensively. When the fuel is removed from the core, and shipped to a reprocessing plant, this will eliminate the major source of radiation at the site. As this will be done in the same manner as in a refueling operation, well-known techniques will be used. In addition, the removal and decontamination of plant components could be accomplished by use of techniques developed by the utility for routine maintenance and component replacement during the plant's life. With the predictably increasing difficulty in locating suitable plant sites, it is very unlikely that a location would be completely abandoned, with resulting problems of protecting the general public against residual radioactivity. The actual retirement of nuclear plants is thus not seen to be a major problem for the remainder of this century.

Nuclear Fuel

Fuel Cycles

The fuel cycle used in the great majority of power reactors today is based on the fissioning of uranium 235. It has been found economical in the U.S. to use "enriched" uranium having a greater content of the U-235 isotope than the 0.711 percent present in natural uranium, and such fuel is available from the enrichment plants presently owned by the U.S. Government. When speaking of fuel cycles, it should be noted that the term encompasses all activities involving fuel including those outside the reactor such as fabrication, transportation, and reprocessing.

The fissioning of U-235 in the presence of the naturally occurring nuclides Uranium 238 (U-238) and Thorium 232 (Th-232) leads to the production of other fissile material called bred fuel. If U-238 is the fertile material, the primary fissile material produced is Plutonium 239 (Pu-239), and the process is known as the uranium-plutonium cycle; while for Th-232, the primary fissile material produced is U-233, and the process is known as the thorium cycle. These bred fuels are of great importance to nuclear power because of the increased supply of fissile material resulting from their production and because of their superiority to U-235 as fissile materials in breeder reactors.

The fissile material bred in the reactor can be incorporated into new fuel, provided enough is produced to make the necessary reprocessing of the discharge fuel economic. There will not be enough recycle fuel to supply all reactors, so that some new uranium fuel will be required even after breeder reactors come into wide use.

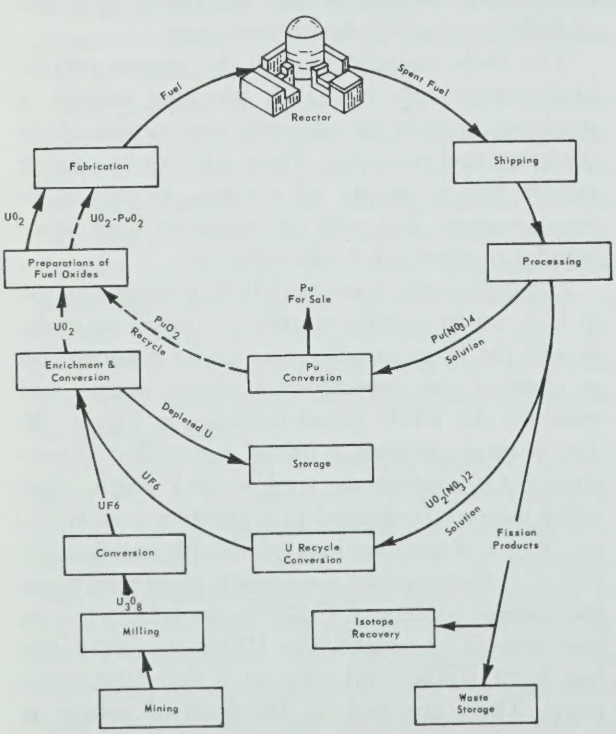
The light water reactors (LWR) presently in use in U.S. utility systems employ the uranium cycle, as will the large number now under construction or planned. An example of a typical overall fuel cycle for the LWR plants is shown in Figure 18. The natural uranium is mined and milled to produce U_3O_8 concentrate (yellowcake) which, after being assayed, is shipped to a plant for conversion to UF_6 gas of specifications suitable for enrichment. The U.S. Government enrichment plant then raises the isotopic content of U-235 in the UF_6 to two to four percent by weight. The UF_6 is converted into fuel form (UO_2) and sent to a fuel fabrication plant. There the fuel, in the form of pellets, is

clad in long cylindrical tubes to constitute fuel rods, which in turn are bundled into fuel assemblies, which are shipped to the reactor and placed in service. After irradiation, the assemblies are placed in a spent fuel pool at the reactor station for a time to allow their radioactivity to decrease to a suitable level to facilitate subsequent handling. The elements are then shipped to a reprocessing plant for recovery of uranium, plutonium, neptunium, and possibly other elements.

The thorium fuel cycle is similar to the uranium cycle but differs in these respects: Th-232 is introduced at the fuel preparation stage in place of U-238; the required quantity of U_3O_8 is fed to the cycle and is converted to UF_6 of high U-235 enrichment for makeup fissile material; and U-233 and other uranium isotopes of the thorium chain will be returned from the reprocessing plant to the cycle as they become available. In civilian power applications, the thorium cycle is limited at present to the experimental molten salt reactor and demonstration in the Peach Bottom High Temperature Gas Cooled Reactor (HTGR) plant although a larger HTGR plant, Fort St. Vrain, is under construction and a thorium breeder demonstration core is planned for Shippingport.

Development is underway to introduce plutonium recycle into commercial use by the mid 1970's when plutonium in excess of research and

FIGURE 18
NUCLEAR FUEL CYCLE FOR LWRs



development requirements will begin to accrue from the LWR's. This production of plutonium in the LWR's will also be valuable eventually for the introduction of fast breeder reactors into the generation complex which is expected to occur in the early 1980's. Due to the fast breeder's superior utilization of plutonium as a fissile material, they will have priority on its use as their initial fuel charge.

The preceding descriptions of the uranium and thorium cycles and their recycle variations deal principally with their use in LWR and advanced converter (HTGR) reactors. The same cycles also apply to breeder reactors. The physics and economics of each cycle are such as to make each singularly favorable for a particular type of breeder. In a fast (high kinetic energy) neutron spectrum, the cycle which utilizes plutonium as the fissile material and U-238 as the fertile material produces a greater conversion of fertile material to new fissile material per unit consumption of original fissile material in a fuel loading. In other words, the so called "conversion" or "breeding" ratio is higher. Furthermore, a fast reactor fueled with U-235 would require a fissile inventory about 50 percent greater than one fueled with Pu. Because of this greater breeding ability of the plutonium-uranium cycle, fast breeder development is centered on plutonium fuel. The production of plutonium in the LWR's of the 1970's and 1980's is compatible with this trend.

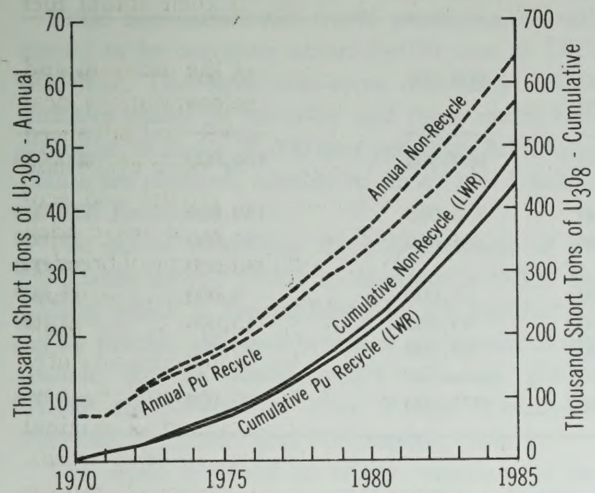
On the other hand, the thorium cycle with U-233 as the primary fissile material in the presence of Th-232 promises the highest breeding ratios in a thermal neutron spectrum and establishes the potential for a true breeding cycle in a thermal reactor. The initial thorium cycle reactors have been fueled with U-235, and will continue to require U-235 for makeup until sufficient U-233 is produced and the plant design optimized for breeding.

To appreciate the importance of high breeding ratios, it should be noted that the fast reactor can develop in ten years about twice the fissionable fuel material with which it started. This fuel can be used to keep the reactor operating and to supply at the end of the 10-year "doubling period" sufficient fuel to start a new reactor of equal size. The continual recycling of fissile plutonium bred from fertile U-238 means that eventually 60 percent to 80 percent of the U-238 can be converted and fissioned. As U-238 constitutes 99.3 percent of natural uranium, the fast breeder reactor unlocks a practically inexhaustible supply of nuclear energy.

FIGURE 19

PROJECTED U_3O_8 REQUIREMENTS FOR U.S. NUCLEAR POWER PLANTS

(Based on AEC Estimates, Sept.1969)



In contrast, the LWR of present design utilizes only one percent to two percent of the energy in natural uranium. The usefulness of the FBR is further emphasized by the existence of a large quantity of depleted uranium (tails) left over from operations at the AEC's uranium enrichment plants. This material can serve as replenishment U-238 for the FBR for many years to come.

Fuel Utilization

1. *Uranium Fuel Requirements*

From estimates of the growth of nuclear power by the U.S. Atomic Energy Commission, which forecasts a median of 150,000 mw of nuclear plant capacity installed by 1980, the uranium ore requirements through the year 1985 have been developed and are shown in Figure 19. The curves show annual and cumulative uranium requirements, in short tons of U_3O_8 with and without recycle of plutonium. These estimates were made considering fuel cycle lead times, reactor operating characteristics, and operation of uranium enrichment plants to a tails assay of 0.2 percent U-235. Further projections indicate that the cumulative requirement of approximately 450,000 short tons by 1985 will increase to a requirement of about 700,000 tons by 1990. This estimate is based on the assumption of a U.S. nuclear generating capacity of one million megawatts in the year 2000, plutonium recycle in LWR plants on a commercial scale beginning in the mid 1970's and introduction of the breeder reactor on a commercial basis by the mid 1980's.

During the early years after introduction of the breeder reactor (FBR) into the U.S. generation complex, there will be an actual increase in the requirements for uranium despite the eventual role of the FBR in reducing drastically the need for uranium. Increasing amounts of plutonium bred in the LWR's will be diverted to fueling the FBR's instead of being recycled in LWR's. The additional incremental tonnage of uranium required to accommodate this transfer, however, should not be large compared to the total needs of the period. Figure 20 illustrates how the introduction of fast breeders would cause the overall requirements for uranium to decline rapidly as the FBR's take the major role in nuclear power. However, if the introduction of breeders is delayed, or sufficiently high breeding ratio is not achieved, considerably more uranium than estimated would be required, as indicated by the dashed line in Figure 20.

Substantial sales of uranium have been made to the utilities or their nuclear system suppliers for their requirements in the near future. Commitments have been made for over 80 percent of their delivered requirements for the next five years. The majority of the ore requirements beyond that time, however, remained to be purchased.

The energy in nuclear fuel is highly concentrated, and it can be economically transported anywhere in the world. Therefore, nuclear developments in other parts of the world must be considered. The European Nuclear Energy Authority has forecast that the non-communist world nuclear generating capacity will be 18,000 megawatts in 1970, 118,000 in 1975, and 305,000 by 1980. They estimate corresponding annual U_3O_8 requirements

FIGURE 20

EFFECTS OF FAST BREEDER INTRODUCTION

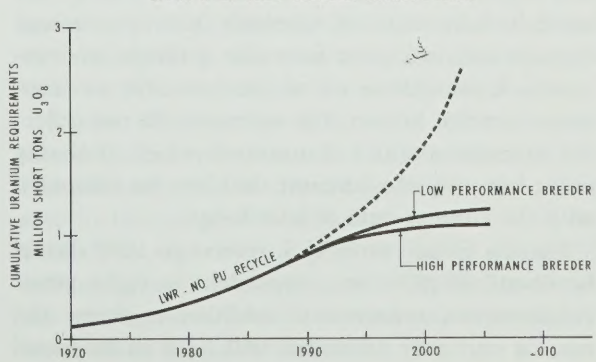


TABLE II–8

Estimates of U.S. and Non-Communist Resources of Uranium (Tons U_3O_8)—Jan. 1, 1970

	Less than $10		$10 to $15	
	Reasonably assured resources	Estimated additional resources	Reasonably assured resources	Estimated additional resources
United States:				
Uranium deposits	250,000	600,000	140,000	300,000
By-product	90,000		20,000	
	340,000	600,000	160,000	300,000
Other non-Communist countries:				
Canada	232,000	230,000	130,000	170,000
South Africa	200,000	15,000	65,000	35,000
Sweden			350,000	50,000
France	45,000	25,000	9,000	15,000
Nigeria	26,000	39,000	13,000	13,000
Others	87,000	66,000	33,000	17,000
Total, including United States	930,000	975,000	760,000	660,000

of 10,000 tons in 1970, 38,000 tons in 1975, and 78,000 tons in 1980.

2. *Availability of Uranium Ore*

In Table II–8 are tabulated estimated United States and non-communist world resources of uranium at various extraction costs. Resources in the United States, shown in the upper part of the table, occur as deposits principally mined for their uranium content and as very low grade concentrations in deposits from which they may be recovered as a by-product, principally from copper and phosphate mining operations.

Reasonably assured resources are contained in known deposits, and the estimates are based on sample data, measurements and knowledge of ore body habits. In the less than $10 category, the estimates are equivalent to ore reserves as the term is used in the mining industry. For higher priced categories, information is not as well developed and the estimates in part rely on statistical analysis. The estimated additional resources are those postulated in extensions of currently known uranium deposits and in known favorable geologic environments. Inasmuch as all of the favorable environments are not known, the estimates do not reflect the ultimate amount of uranium which probably exists but only the amount that can be estimated with the current state of knowledge.

Since a conservative U.S. reserve in 1980 should be about 400,000 tons, equivalent to eight years' requirements, resources in addition to those that can be currently estimated will have to be found well before 1980 if U.S. requirements are to be met from domestic reserves at prices less than $10 per pound of U_3O_8. In the U.S. in response to this requirement, exploration drilling increased from 4.2 million feet in 1966 to about 30 million feet in 1969. A high level of effort must be sustained to assure a balance between exploration effort and production requirements.

The lower portion of Table II–8 shows the resources for the rest of the non-communist world as developed in a joint study of the European Nuclear Energy Authority and the International Atomic Energy Agency (Uranium Resources, Production, and Demand, 1970). As can be seen, Canada and South Africa are the principal current sources of additional low cost uranium, with Sweden having important resources in the plus $10 price category. As South African production is largely a by-product of gold mining and Canadian production is from only a few mines, there are limitations on the rate of production of these resources.

3. *U_3O_8 Production Capability*

United States uranium production capability is currently (1969) about 15,000 tons of U_3O_8 per year. This will increase in the next few years to about 19,000 tons per year. Plans have been announced for the construction of several new production facilities. Current and planned production capabilities appear adequate to fill requirements to the mid-seventies. Toward the end of this century, the operation of fast breeders with their ability to

produce sufficient fuel for themselves and the growth of the electric power industry will result in a reduction in the requirements for ore production and refining facilities. This will become an increasingly important consideration in the development of new production facilities as the years pass by.

Total non-communist world production is estimated to be currently about 24,000 tons of U_3O_8 per year. The total near-term capability, which includes plants on stand-by and those under construction, is about 38,000 tons per year. Additional plants are planned, notably in Africa and Canada.

4. *Toll Enrichment*

The act of increasing the concentration of the fissionable isotope U-235 in uranium is called enriching which is accomplished in the gaseous diffusion process. All enrichment is performed at the Atomic Energy Commission's diffusion plants, which are located at Oak Ridge, Tennessee; Paducah, Kentucky and Portsmouth, Ohio.

The work required to enrich uranium is expressed in units of separative work. A product of one kg of two percent enriched uranium requires approximately 2.2 kg of separative work if the feed material is natural uranium.

Under the toll enrichment service presently available, privately owned uranium in the form of uranium hexafluoride (UF_6) is delivered to the Commission as feed. The product of enriched UF_6 is returned to the customer. The present charge for this service is $28.70 per kg of separative work, and is scheduled to increase to $32.00 in September 1971.

Table II–9 indicates the future separative work requirements estimated in 1969 by the AEC. These requirements include those for a capacity of nuclear power plants utilizing enriched uranium fuel projected to reach 150,000 mw in the U.S. and 95,000 mw in the rest of the non-communist world, exclusive of Great Britain, by 1980. Table II–10 shows the production planned for the U.S. gaseous diffusion plants to meet these requirements. The plan takes advantage of pre-production in excess of demand in the early years to meet later requirements and includes future implementation of a cascade improvement program (CIP) and a power uprating program (CUP).

Another area under study by both private industry and the AEC is the possibility of private ownership of the enrichment facilities. During the past few years, a number of studies by industry and government have considered the possibility of private ownership of the enrichment facilities. Alternatives ranging from a Government corporation to separate private ownership of individual plants have been considered. The complex questions with regard to national security, competition, financing, and economics and the pressing need to proceed with uprating and improving the facilities to meet the industry's growing needs have resulted in a Government decision to continue its present ownership of the diffusion plants. However, AEC has indicated it will share its enrichment technology with private U.S. organizations carrying out independent development work on enrichment.

It should be noted that some countries believe that the gas centrifuge may prove to be a more economical method of enriching than the diffusion plant, and development of the process is underway in the U.S.A. and abroad.

5. *Coupling of LWR and LMFBR Through Pu Recycle*

The production of fissile plutonium in the LWR and its recovery during the reprocessing of spent fuel constitute an opportunity to conserve the world's supply of nuclear ores. As explained in the discussion of fuel cycles, appreciable quantities of this recovered plutonium will become available in the next decade. Nuclear plants now in operation, under construction and firmly committed in the U.S. will be producing approximately 11,000 kilograms of fissile plutonium annually in the mid-1970's. Annual fissile plutonium recovered by the early 1980's is expected to be around 30,000 Kg, based on present projections of nuclear power growth in the U.S.

In the mid-1970's this plutonium will begin to be in excess of research and development needs in the U.S., including the requirements of the fast breeder demonstration plants. The utilities owning the bred plutonium will be faced with the decision of storing it for ultimate use in fast breeder reactors or making it available for recycle into LWR's. The chances are that the former alternative will not be economical, given introduction of the commercial fast breeder reactor in the U.S. no sooner than the early 1980's. Rather than carry costly inventories of plutonium with no satisfactory returns available in the near term, the utilities could have recourse to recycle in existing reactors.

Figure 19 shows how this would affect the projected U_3O_8 requirements for U.S. nuclear plants. Plutonium recycle in thermal power reactors would save in the order of 50,000 short tons of U_3O_8 by 1985. This represents a gross saving of about 750 million dollars at today's price levels, and to obtain the true net saving, the increased plutonium fabrication costs should be deducted.

TABLE II–9

Summary of Projected Separative Work Requirements—Committed and Anticipated

[Separative work in thousand of kilogram units]

Date (fiscal year)	Central station power[1]: Domestic: Under allocation and/or contract	Domestic: For stations which have been announced[2]	Domestic: Anticipated	Domestic: Total	Foreign: Under agreements for cooperation (including contracts)[3]	Foreign: Anticipated	Foreign: Total	Other civilian requirements: Domestic	Other civilian requirements: Foreign	Other civilian requirements: Total	Total separative work requirements: Defense and other Government requirements total	Total separative work requirements: Annual	Total separative work requirements: Cumulative
1970	1,910	2,400	...	2,400	900	...	900	270	170	440	3,650	7,390	...
1971	1,690	3,000	...	3,000	1,500	...	1,500	230	180	410	620	5,530	12,920
1972	1,220	4,500	...	4,500	2,000	...	2,000	[4] (90)	230	140	480	7,120	20,040
1973	1,130	6,100	...	6,100	2,600	...	2,600	160	230	390	860	9,950	29,990
1974	1,300	8,500	...	8,500	3,300	...	3,300	70	250	320	180	12,300	42,290
1975	1,130	7,600	2,300	9,900	4,600	...	4,600	130	250	380	760	15,640	57,930
1976	1,230	9,400	1,700	11,100	4,400	1,200	5,600	160	250	410	1,400	18,510	76,440
1977	1,070	8,500	4,400	12,900	4,700	2,300	7,000	230	250	480	830	21,210	97,650
1978	1,260	9,200	5,800	15,000	4,600	3,900	8,500	140	280	420	600	24,520	122,170
1979	1,290	9,400	7,800	17,200	4,300	5,300	9,600	220	280	500	900	28,200	150,370
1980	1,270	9,300	10,200	19,500	4,500	6,000	10,500	270	280	550	2,700	33,250	183,620
Total	14,500	77,900	32,200	110,100	37,400	18,700	56,100	1,790	2,650	4,440	12,980	...	...
1981 through 2008	25,100	...	...	...	37,200	...	...	...	...	...	...	...	...

[1] Requirements based on "most likely" forecast of nuclear power growth.

[2] Includes separative work under allocation and/or contract.

[3] The total magnitude of the commitment under the "Agreements for Cooperation" is known within the limits of the fuel cycle assumptions, the annual rate at which separative work will be required is somewhat uncertain until uranium enrichment services contracts are negotiated.

[4] Anticipated returns exceed withdrawals.

TABLE II–10

Projections of Diffusion Plant Power Levels and Separative Work Availability versus Separative Work Requirements

[Separative work in thousands of kilogram units]

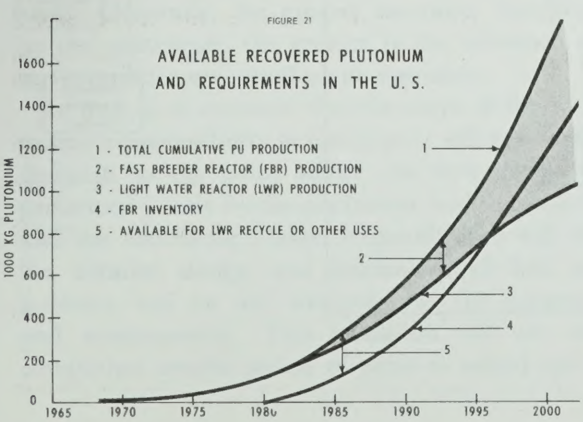
	Fiscal year— 1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
Average annual power level, 3 sites (megawatts)	1,975	2,420	2,895	3,670	4,711	4,919	5,330	5,963	6,779	7,204	7,261	7,381
Annual separative work production	6,887	8,221	9,709	12,083	15,188	16,422	18,430	20,987	24,080	25,626	25,734	25,933
Includes separative work:												
From CIP of	...	...	...	...	320	1,070	2,150	3,200	4,100	4,560	4,630	4,630
From CUP of	...	...	...	...	...	...	...	1,000	2,810	3,890	3,930	4,130
Cumulative separative work available including the July 1, 1969 inventory of 13,325,000 units	20,212	28,433	38,142	50,225	65,413	81,835	100,265	121,252	145,332	170,958	196,692	222,625
Annual separative work requirements[1]	7,390	5,530	7,120	9,950	12,300	15,640	18,510	21,210	24,520	28,200	33,250	[2] 43,070
Cumulative separative work requirements	7,390	12,920	20,040	29,990	42,290	57,930	76,440	97,650	122,170	150,370	183,620	226,690
Separative work in prepproduction inventories	12,822	15,513	18,102	20,235	23,123	23,905	23,825	23,602	23,162	20,588	13,072	...
Separative work requirements from new plant cumulative	...	...	...	...	...	...	...	...	...	...	...	4,065

[1] See table II for details through 1980.

[2] Includes a working inventory equivalent to 2 months of 1982 require ments (6,130

With the advent of the commercial fast breeder reactor expected in the 1980's, the use of available plutonium will shift progressively from the LWR to the FBR, as shown in Figure 21. Due to the large number of the LWR's that produce Pu in the U.S., its supply for fueling the fast breeder should be ample for the rapid introduction of the FBR when the technical and economical obstacles have been overcome.

Figure 21 shows that some plutonium is always available for LWR recycle, and other uses even after the FBR plants would be expected to have taken over base load generation on U.S. systems. The amount of excess Pu will depend, of course, on the number of LWR's in operation at the time of introduction of the FBR's, the amount of Pu recycled in the LWR's, the rate at which the FBR's are built, and the fuel inventory, and fissile production characteristics of the FBR's. In the long term situation the nuclear power complex can be optimized for the economic use of excess Pu, and the cost of nuclear power will be essentially independent of the price of uranium. The uranium would be required only as a source of fertile U-238 for conversion into Pu, and the present reserve of depleted uranium from diffusion plant operations can supply this need for the next 50 years. Thus, it is expected that the compatibility of the LWR and FBR, due to their coupling by the plutonium produced in the uranium cycle they both employ, will provide the economic flexibility necessary for a smooth transition to a complex dominated by the fast breeder and with satisfactory utilization of nuclear fuel resources. In the meantime, the HTGR, through use of the thorium cycle offers a means of conserving uranium and, as another competitor, could assist in holding down power costs while the FBR is being developed to commercial status.



Fuel Management

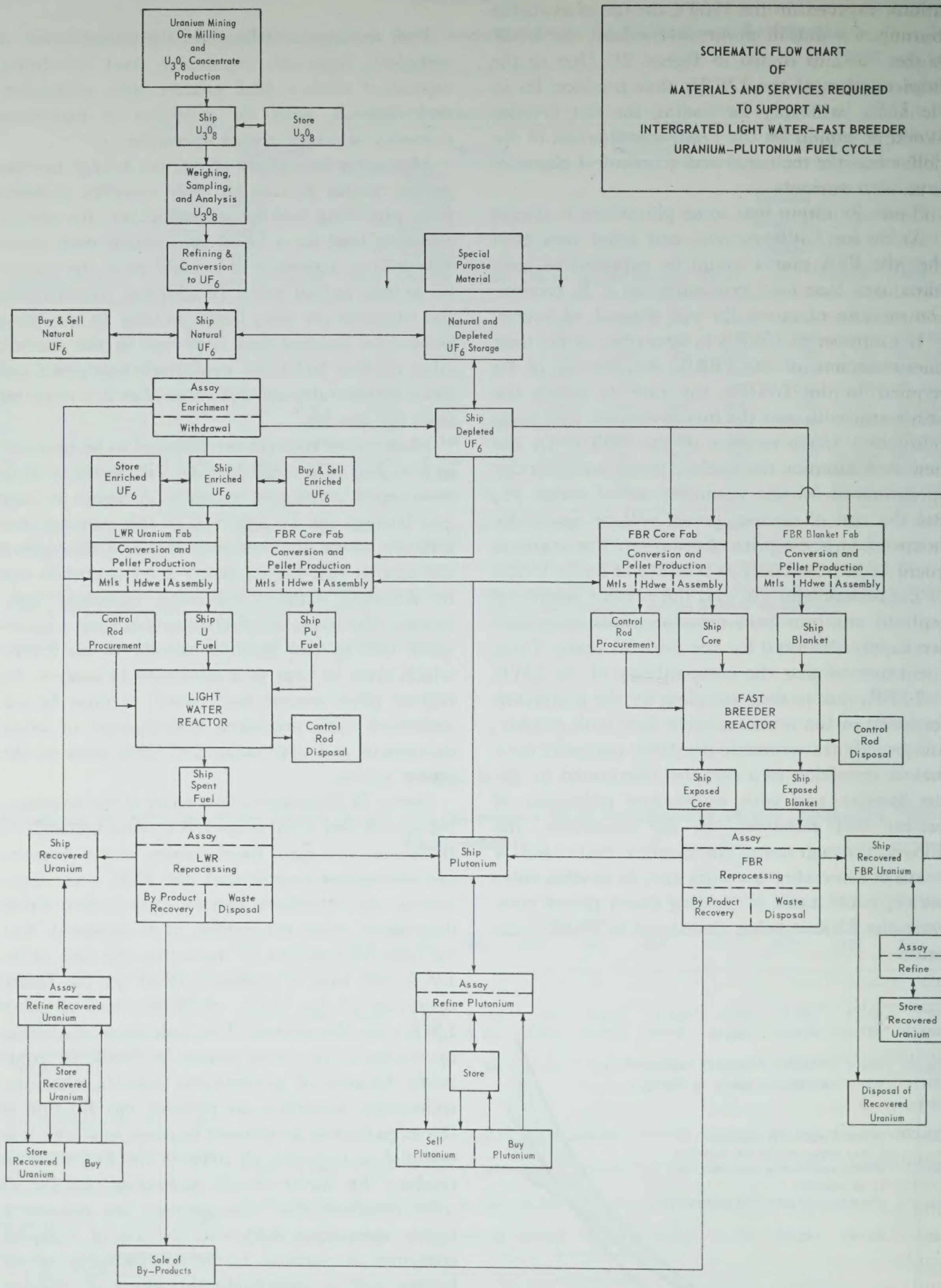
Fuel management involves the coordination of technical, financial, regulatory, and scheduling aspects of nuclear fuel procurement, utilization, and disposal, with the objective of maximum economy of power system operation.

Managing the supply of fuel for a large nuclear power reactor is a much more complex problem than providing fuel for a fossil plant. An annual refueling load for a 1,000 mw reactor costs about $10 million, and some of it could be in the reactor for as long as four years. In addition, payments for the uranium ore may begin as long as two years before the finished fuel is placed in the reactor. Also, nuclear fuel is not completely consumed and has a considerable salvage value after it is removed from the reactor.

Most power reactors are planned to be operated so that part of the fuel loading will be removed or rearranged in the core annually. A higher average fuel burnup can be achieved in this manner, and a flatter power distribution is obtained throughout the core so that higher power level operation can be achieved without exceeding operating limitations. However, the fuel rearrangement can require one to two months' outage of an LWR, which must be kept to a minimum to achieve the highest plant annual load factor. It must be coordinated with necessary maintenance of other equipment and with outages of other units on the power system.

Figure 22 illustrates a flow chart of the uranium-plutonium fuel cycle of an LWR. Also included in the center and right hand portion of the diagram are plutonium recycle and the FBR cycle illustrating the interfaces between the cycles. From discussions presented earlier, it is apparent that the policies followed in managing the fuel of an LWR will have a profound effect on the future operation of the LWR, of FBR's, and of other LWR's in the system. The unit costs of certain operations in the cycle cannot be predicted accurately because of government policies, changing technology, uncertain ore reserves, etc. Because of the large capital investment in plant and fuel, it is essential to optimize all parts of the fuel cycle to produce the lowest overall generating cost for all units involved. Fuel management has become a highly specialized field, and the use of a digital computer is essential to permit inclusion of all factors and to investigate the effect of altering variables. Subject to the constraints imposed by materials limitations, heat removal considerations,

FIGURE 22


SCHEMATIC FLOW CHART
OF
MATERIALS AND SERVICES REQUIRED
TO SUPPORT AN
INTERGRATED LIGHT WATER–FAST BREEDER
URANIUM–PLUTONIUM FUEL CYCLE
Uranium Mining Ore Milling and U3O8 Concentrate Production
Ship U3O8
Store U3O8
Weighing, Sampling, and Analysis U3O8
Refining & Conversion to UF6
Special Purpose Material
Buy & Sell Natural UF6
Ship Natural UF6
Natural and Depleted UF6 Storage
Assay
Enrichment
Withdrawal
Ship Depleted UF6
Store Enriched UF6
Ship Enriched UF6
Buy & Sell Enriched UF6
LWR Uranium Fab
Conversion and Pellet Production
Mtls
Hdwe
Assembly
FBR Core Fab
Conversion and Pellet Production
Mtls
Hdwe
Assembly
FBR Core Fab
Conversion and Pellet Production
Mtls
Hdwe
Assembly
FBR Blanket Fab
Conversion and Pellet Production
Mtls
Hdwe
Assembly
Control Rod Procurement
Ship U Fuel
Ship Pu Fuel
Control Rod Procurement
Ship Core
Ship Blanket
LIGHT WATER REACTOR
Control Rod Disposal
FAST BREEDER REACTOR
Control Rod Disposal
Ship Spent Fuel
Ship Exposed Core
Ship Exposed Blanket
Ship Recovered Uranium
Assay
LWR Reprocessing
By Product Recovery
Waste Disposal
Ship Plutonium
Assay
FBR Reprocessing
By Product Recovery
Waste Disposal
Ship Recovered FBR Uranium
Assay
Refine
Store Recovered Uranium
Disposal of Recovered Uranium
Assay
Refine Recovered Uranium
Store Recovered Uranium
Store Recovered Uranium
Buy
Assay
Refine Plutonium
Store
Sell Plutonium
Buy Plutonium
Sale of By-Products

and the reactor system, there are several considerations involved in designing for the optimum fuel burnup. Per unit of energy released in the reactor, higher burnup of fuel material will reduce the fabrication and reprocessing costs, but higher enrichments will increase the fuel material costs. Working capital charges naturally vary with the dollar value of the fuel. The frequency of reloading is another variable since the plant capacity factor and energy output will be affected.

At present, utilities depend on the supplier of the nuclear steam supply system to furnish the initial core loading. The three general types of fuel contracts now common in the industry are:

1. *Comprehensive fuel cycle service.*—The fuel supplier contracts to supply all materials and services required to provide fuel to meet the reactor's operating requirements and assumes complete responsibility for disposal of the spent fuel. Prices for the new fuel assemblies and buy-back prices for the spent fuel are usually quoted in cents per million Btu's of rated energy. The supplier provides all necessary fuel design analysis required and warrants energy cost from the fuel.

2. *Comprehensive fuel supply service.*—This is essentially the same as a comprehensive fuel cycle service except that responsibility for disposal of the spent fuel remains with the utility.

3. *Fabrication service.*—The utility is responsible for procurement of uranium, conversion to UF_6, and enrichment of the uranium. It owns the spent fuel when it is discharged. The contractor performs the fabrication which may be priced either in cents per million Btu's of rated energy or on a dollars per kilogram of contained uranium basis.

Warranties offered by the contractors play a very important role in fuel economics. Appropriate warranties can provide some assurance to the utilities regarding levels of actual fuel cost but may result in loss of flexibility by the utility to manage its own fuel to meet best its individual needs. Generally, the greater assurance provided by the contractor, the greater is the influence of the contractor on actual plant operation.

In time, it is expected that the scope of the contractor's responsibility in fuel supply will gradually diminish to the point where the core design is performed jointly by the contractor and the utility, and the contractor's basic responsibilities will be the detailed design and fabrication of fuel assemblies, and he will warrant only the material and workmanship. This transition will be accomplished over a period of years as actual operating experience is gained and as utilities build up staffs with the requisite knowledge.

Contractual obligations for the fuel materials and services required in the various parts of the fuel cycle vary widely in scope, terms, and conditions. Fabrication contracts normally are tied to a particular unit while most other contracts will be generally applicable to overall system requirements. The majority of the U_3O_8 requirements will probably be provided through long-term contracts (five to 15 years) which have rather rigorous requirements to take delivery of specific amounts at particular times. To obtain the necessary flexibility to meet system requirements in an economical manner, these contracts may be supplemented by shorter-term contracts, spot purchases, and possibly by the resale of U_3O_8, natural UF_6, and enriched UF_6. Recovered uranium and plutonium from the discharged fuel will be phased back into fuel supply activities in accordance with the prevailing market situation and the overall fuel management strategy. Enrichment and reprocessing are also items which will probably be covered by long-term contracts which may have more flexibility than the long-term U_3O_8 contracts. The rest of the services will generally be covered by shorter-term contracts.

If a basic change is made in a unit's fuel loading to lengthen or shorten the scheduled interval between refueling, or if fuel is discharged early, or if operation is extended beyond the depletion of reactivity in order to meet scheduled refueling dates or schedule changes, the consequences of such changes are not limited to the current cycle but will materially affect the length of subsequent cycles and/or reload batch designs for a period of three to five years. At the time a fuel batch is being loaded into the reactor, delivery of uranium concentrates would normally be completed, and final design would be nearing completion for the next replacement batch. Also, procurement activities on the following batch would be getting started. When a change in operating plans for a unit is made, modification in supply requirements for batches already in production and those in advanced planning stages must be made to conform to the new situation. While such changes upset previous plans, in the long run this may be the most economical course to follow for the system as a whole.

Nuclear plants do not have the inherent flexibility of fuel supply typical of coal-fired plants. Various key nuclear fuel supply commitments must be made firm from six to 30 months in advance of

the anticipated time when the fuel is to be placed in the reactor. Nuclear fuel cannot, in general, be shifted from one unit to another of a different type or design to meet unanticipated needs although standardization of fuel element design will be a step in this direction. Therefore, nuclear plant generating capacity is more vulnerable to outages due to lack of fuel than are coal-fired units. To reduce fuel cycle inventory charges, the time between delivery of the fuel and actual insertion in the reactor must be minimized to the extent practical.

To appreciate the complexities involved in economic optimization of system expansion and operation, it is necessary to consider the problem in the context of a mixed system in which a substantial portion of the system capacity is comprised of nuclear units. The rigorous scheduling requirements brought on by batch refueling, together with the requirements to meet immediate and future system loads reliably and economically, necessitate a high degree of detailed long-range planning of system loading and fuel procurement activities.

Since it is impossible to make accurate predictions of the load, availability, and reliability of generating units, the effects of these uncertainties on the economic factors of the fuel cycle cost must be continually examined by personnel responsible for the fuel management program.

In summary, the principal benefits expected from effective fuel management are cost savings due to:

a. Reduction in overall system generation cost by having the ability to tailor fuel requirements and utilization of individual units to fulfill best the system needs.
b. Stimulation of competitive pricing of goods and services in the marketplace to meet fuel cycle needs.
c. Reduction in inventory cost through effective integration and coordination of procurement and logistic activities to meet system needs.
d. Optimization of fuel design for a utility's particular economic considerations and system characteristics.
e. Improved fuel performance through optimization of in-core fuel utilization.

Waste Management

The disposal of waste material from a nuclear plant is, of course, vastly different than that from a fossil plant. Although the weight and volume are less by orders of magnitude, the radioactivity contained in them dictates extreme care in their handling and storage. The largest quantity of waste material is contained in spent fuel elements, which as noted in earlier sections, are shipped off-site to a fuel reprocessing plant. Relatively small quantities of radioactive liquids and solids are accumulated as a result of normal operations and maintenance. A typical reactor facility has provisions for temporary storage of such wastes, and possibly equipment for reducing its volume. Regulations require that any permanent storage of long-lived radioactive wastes be under the control of a perpetual entity, which means a government body. Therefore, all waste material eventually will pass into custody of one of the Federal or State controlled disposal sites.

Improvements in fuel technology and methods of reprocessing in the past ten years have reduced markedly the volume of high-activity wastes generated per unit of power produced. The conversion of the high-level liquid wastes to stable solids, with subsequent long-term storage or disposal in selected geologic formations such as salt, has been demonstrated on an engineering scale. This technology, which has been developed during the past ten years, has provided the basis for a proposed Atomic Energy Commission policy on high level waste management. In this proposed policy, all high-activity waste from industrial fuel reprocessing will be solidified and transferred to a Federal Repository within ten years following separation of fission products from the irradiated fuel. When this policy is implemented, the levels of stored high level waste in liquid form are expected to be nominal.

Cost Factors of Nuclear Plants

Capital Costs

Because the nuclear industry is in a stage of dynamic growth, it is difficult to establish precise data for the present and future costs of nuclear plants. The nuclear industry today is characterized by an unprecedented commitment of new technology which has been reflected in uncertainties in capital costs attributed to delayed deliveries of vital components, the introduction of new or more stringent codes and standards, changes in regulatory requirements, and the extension of construction schedules coupled with current high interest

TABLE II–11

Comparison of 1000 Mw LWR Power Plant Cost Estimates

Thousands of dollars

	March 1967	June 1969	June 1970
Direct costs:			
Nuclear steam supply	33,780	40,420	45,800
Turbine generator	27,100	29,780	32,700
Construction materials and equipment	23,300	35,400	47,000
Construction labor	20,800	33,400	55,800
Total direct costs	104,980	139,000	181,300
Indirect costs:			
Owner's cost	5,490	5,900	6,200
A/E and construction management	6,280	11,500	11,800
Miscellaneous construction cost	2,050	1,700	1,700
Land and land rights	1,090	900	1,000
Total indirect costs	14,910	20,000	20,700
Contingency	3,010	9,400	12,900
Total construction cost	122,900	168,400	214,900
Escalation:			
Escalation, T&G 6 percent year [1]	([2])	1,700	2,000
Escalation, balance	([2])	[3] 19,200	[4] 57,400
Interest during construction	10,840	28,300	48,800
Total cost	133,740	217,600	323,100

[1] 6 to 12 months delay in T–G delivery.

[2] Escalation not generally estimated in 1967 due to more stable cost base and option of turnkey proposals which did not include escalation provisions.

[3] Estimated 4 percent per year.

[4] Estimated 12 percent on construction labor and 5 percent on materials and equipment per year.

rates and escalation in costs of labor, equipment and materials.

An indication of the escalation in estimated capital costs for a 1,000 mw LWR plant is provided in Table II–11 which shows that the approximately $135 per kw estimates for this size plant made in March, 1967 had increased to about $220 per kw when estimated in June of 1969, and to more than $320 in 1970. It will be noted that the estimates for virtually all of the components of the plant direct and indirect costs increased substantially. These increases in combination with lengthening construction schedules, labor rates and interest costs resulted in an estimated overall plant cost in 1970 of almost 2½ times that estimated in 1967. It should be noted that the 1967 data do not include any escalation since this was either not considered to be a significant factor at that time or the option of a turnkey proposal was available in which the supplier took the risk of escalated costs.

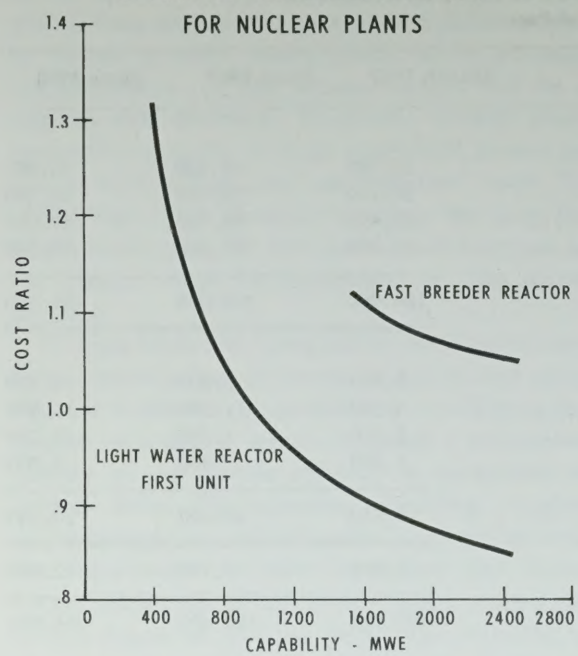
Figure 23 presents an estimate, in constant dollars, of the capital investment for plants of various capabilities. The considerable reduction in cost per kw with increasing unit size is apparent. This curve is not meant to imply that units of 2,000 mw could be purchased "off the shelf" at this time; the average size unit committed at this time is about 950 mw and the largest about 1,150 mw. However, there is no question that larger units will become available before 1990.

It is estimated that cost reductions will accrue in the future through increased business volume and acquired experiences in construction techniques and component design factors. These reductions could be in the order of $10–15/kw. Other factors that can have a profound influence on cost are licensing requirements, site preparation, cooling water requirements, labor productivity, and rates, inflation, etc. that make future predictions highly unpredictable.

The very large capital requirements for nuclear plants make their costs sensitive to interest rates,

FIGURE 23

ESTIMATED CAPITAL INVESTMENT FOR NUCLEAR PLANTS



NOTE: DUE TO CONTINUED ESCALATION OF COSTS, DATA HAVE BEEN PLOTTED AS A RATIO, WITH THE COST OF A 1000 MW UNIT AS A BASE.

taxes, insurance, depreciation, etc. The comparatively long periods required for licensing and construction can cause considerable variations in interest during construction. Slippage in construction schedules, regardless of the reasons, thus can result in a significant increase in the capital cost of a nuclear plant. Adhering to the shortest possible schedule of construction is one of the most serious problems facing the industry now and in the foreseeable future.

Efficiency

The current light water reactors produce steam which is at temperatures and pressures roughly comparable to the conditions for fossil plants which were being built in the 1930–1940 period. Therefore, the cycle efficiencies of the current design for light water plants are relatively poor when compared to modern fossil fueled generating plants. The turbine cycle heat rates for light water reactors are usually in the range of 9,500 to 10,500 Btu per kwh with resulting net plant heat rates in the order of 10,000 to 11,000 Btu per kwh. However, nuclear fuel costs are sufficiently lower than fossil costs to overcome this handicap.

Improved designs which incorporate slightly superheated steam are now becoming available from reactor vendors. Also, turbine-generator manufacturers are making machines available which use one or more stages of steam reheating and very efficient moisture separation facilities in the turbine cycle. These improvements will have a substantial effect on the thermal efficiency of light water reactors. The effect will amount to about a five percent reduction in cycle heat rate for light water reactor units.

The high temperature gas cooled reactor and other advanced concepts which produce steam at conditions comparable to those for modern fossil fueled generating plants will have net turbine cycle heat rates in the order of 7,500 btu per kwh and net plant heat rates in the order of 8,500 btu per kwh. Concepts that would use gas turbines as prime movers for generators in connection with high temperature gas cooled reactors would also be expected to have net plant heat rates in the order of 8,000 to 8,500 btu per kwh.

Improvements in efficiency generally mean an increase in capital costs. It will, therefore, be necessary to compare very carefully the savings resulting from the efficiency increase over the expected life of the plant with the increased capital costs required to achieve the improved efficiency.

Fuel Costs

Nuclear fuel cycle costs are influenced by many more factors than are fossil fuel costs. The nuclear fuel cycles were described in detail in the Nuclear Fuel Section of this Chapter and, of course, the costs of each of the many steps in the cycle will affect the overall cycle cost. It can be appreciated that sufficient experience has not been obtained with some of the operations to establish definitely their costs. The cost estimates that follow have been taken primarily from AEC reports.

Fuel Materials.—The amount of U_3O_8 that will be required in the expansion of nuclear capacity through 1980 is shown in Figure 19, and Table II–8 indicates resources at various price levels in 1970 dollars. After several years of little activity prospecting was accelerated beginning in 1967, reached a peak in 1969, and slacked off somewhat in 1970. Since there is little need to expend funds to prove reserves far in advance of requirements, the uranium industry's prospecting activities are finely tuned to the anticipated market. This has caused the year-to-year fluctuations indicated.

Conversion to UF_6.—Refining to U_3O_8 and conversion to UF_6 for enrichment can be done in only one privately owned plant at present, although

another private plant is soon to become operable. Other companies will enter the field as government operations are phased out. The present base price is $1.04/lb. U. It is anticipated that competition and volume production will reduce this base price after 1980 progressively to $0.92/lb U. in 1985 and remain at that level thereafter. This is a minor segment of the fuel cycle cost.

Enrichment.—At present, enrichment of U–235 over the naturally occurring 0.711 percent can be done only in government owned plants at a cost of $28.70/kg of separative work. This is scheduled to increase to $32.00 in September 1971. The question of private ownership of enrichment facilities is under examination by the AEC. It is not expected that any new facilities will be operative before 1980. A value of somewhat more than $30/kg of separative work for the period under consideration appears reasonable for public or private ownership.

Fabrication.—Predicted costs of fabrication of fuel from the enrichment or recovery plant are listed in Table II–12. This is a major factor in total fuel cycle cost. These costs for a given type of fuel demonstrate a downward trend as greater quantities are handled, processing becomes more efficient, and fuel design is improved. However, as more advanced types of reactors appear, their fabrication costs will be higher because of problems in handling more radioactive and toxic materials such as plutonium. The HTGR fabrication costs are higher because of the particle coating processes that are necessary. The costs of fabrication of all fuels will depend on the success that is achieved in improving processes to overcome inherent technical problems. Despite the problems, four or five firms other than nuclear steam system suppliers have entered this field.

TABLE II–12

Fuel Cycle Fabrication and Reprocessing Cost Estimates

Date	Reactor type	Fabrication (including preparation) ($/Kg)[3]	Reprocessing ($/Kg)[3,4]
1970	LWR [1]	80	31
1980	LWR	60	27
1990	LWR	45	20
1980	LWR [2]	80	29
1990	LWR	55	22
1980	HTGR	140	70
1990	HTGR	100	44
1990	LMFBR [5]	140	40
1995	LMFBR	115	40

[1] Enriched uranium fuel.

[2] Plutonium recycle with natural U makeup.

[3] $/Kg of heavy metal.

[4] Reconversion of reclaimed uranium to UF_6 not included.

[5] The $/Kg charge for the LMFBR is expressed as the average of the charges for core and for blanket.

TABLE II–13

Estimated Spent Fuel Shipping Costs

Reactor type	Shipping costs[1] $/Kg heavy metal	Assumed Average exposure MWD/MT
LWR [2]	4.00	30,000
HTGR	16.00	61,600
LMFBR:		
Oxide:		
Core-axial blanket	42.90	[4] 80,000
Radial blanket	4.90	8,100
Total [3]	26.70	33,000
Advanced:		
Oxide:		
Core-axial blanket	33.20	[4] 97,000
Radial blanket	3.70	6,000
Total [3]	21.70	35,400

[1] Costs given are on a near-term basis; long-term costs are estimated to be about 10 percent less. One way distance 1,000 miles, rail freight.

[2] Both uranium enriched and plutonium recycle types.

[3] Average cost based on total fuel.

[4] Average core exposure.

Reprocessing.—Predicted costs of reprocessing spent fuel to extract fertile and fissile material are also shown in Table II–12. These costs also are higher for the advanced reactors because of the higher levels of radioactivity. Reprocessing volume is estimated to be 4,000 metric tons per year in 1980 and five to six times as much in 1990, which should provide the high plant loading factors that are necessary to reduce unit costs. Disposal and permanent storage of radioactive wastes is included and is 15 percent to 25 percent of the reprocessing cost.

Shipping Costs.—The costs of shipping new unirradiated fuel from the fabrication facility to the nuclear generating station are about one-sixth those of shipping irradiated fuel from the generating station to the reprocessing facility. The estimated cost of shipping spent fuel to the reprocessing facility is indicated in Table II–13. These

estimates include the costs of containers. freight, handling, insurance, and compliance with all applicable regulation. Generally, shipping costs per kg of heavy metal will vary with the design of the elements; the HTGR fuel includes a considerable amount of graphite which increases the volume compared to LWR fuel, and LMFBR fuel would require sodium filled canisters, unless stored long enough for part of the activity to decay.

Financing Costs.—As described under Fuel Management, several options as to fuel ownership are available to a utility. It is expected that competition will result in the costs of all options reaching about the same level.

Total Fuel Cycle Costs.—The major elements that make up the total nuclear fuel cycle costs have been described herein and based on the best available assumptions for these unit costs, the projected total fuel cycle costs for various types of reactors are listed in Table II–14. It should be noted that these are equilibrium fuel costs; for the first three or four years of a reactor's life, some fuel is removed before maximum burnup, resulting in higher costs. Factors other than the direct cost components will likely have a significant effect on total fuel cycle costs; most significant of these are the recycling of bred plutonium in water reactors and the timing of the introduction of fast breeder reactors into the U.S. reactor mix. It will be noted fuel cycle costs for the fast breeders are projected to be considerably lower than the other types in spite of higher capital and fabrication costs. This is because of the value of the excess bred fuel that they will produce and their ability to use inexpensive depleted uranium as fuel material. Thus, fuel cycle costs are the primary incentive to develop the fast breeder for operation in the late 1980's.

TABLE II–14

Equilibrium Fuel Cycle Costs for a 1000 MW Plant

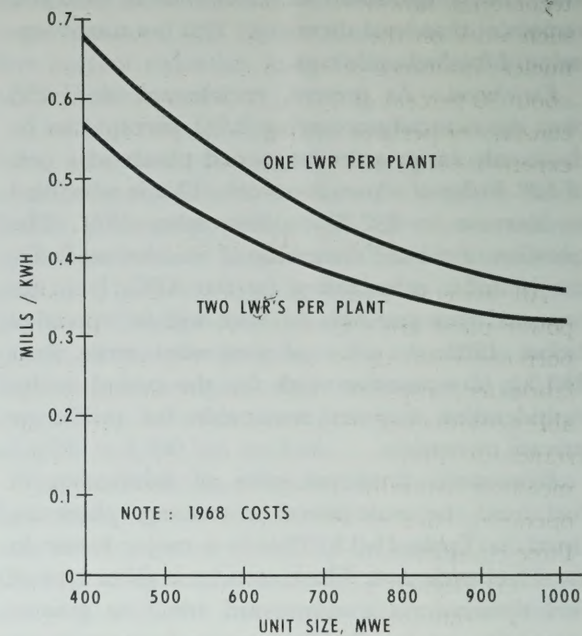
Charge date	Reactor type	Fuel cycle costs mills/Kwh
1970	LWR	1.49
1975	LWR	1.34
1980	LWR	1.23
1985	LWR	[1] 1.20
1990	LWR	[1] 1.19
1995	LWR	[1] 1.26
2000	LWR	[1] 1.46
1980	HTGR	[2] 0.92/1.12
1990	HTGR	0.92
1985/1990	LMFBR	0.7
1995	LMFBR	0.3–0.5

[1] Under burnup conditions given in Table 5–12 in the U.S. AEC publication WASH-1082 entitled "Civilian Nuclear Power."

[2] In accordance with F.C. cost assumptions in the U.S. AEC publication WASH-1097 entitled "The Use of Thorium in Nuclear Power Reactors."

FIGURE 24

OPERATION AND MAINTENANCE COSTS



Operation and Maintenance Costs

Included under the heading of operation and maintenance costs are the charges for fixed and variable maintenance, supplies and expenses, operating labor and nuclear insurance. Figure 24 illustrates estimated costs for the light water reactor plants for various unit sizes. The reason for the decrease in costs is because few, if any, additional personnel are required as the size of nuclear units increase, and thus the operating labor portion per kwh decreases. Also, when a second unit is added at a site, the operating labor portion of the costs does not increase proportionately. Furthermore, technological advances and improved designs combined with increased experience in the maintenance areas are expected to offset any increase in maintenance costs brought about by

larger units. The program of periodic inspection of primary system components, if performed in accordance with the recently issued ASME Standard, will initially add to the maintenance costs and plant down time. Improved inspection tools and techniques, however, should reduce the impact of such work on the overall maintenance costs. The nuclear insurance portion of the cost, amounting to about 30 percent of the total, is expected to remain constant or perhaps show a slight decrease as more experience is gained in the operation of large units.

Quality Assurance

All systems and components of the nuclear power plant are classified according to their importance with regard to safety and are designed, fabricated, inspected, and installed to the applicable provisions of recognized codes, and to quality standards that reflect their importance. These measures naturally are reflected in the capital and operating costs of the plant. The items fall into three classifications:

(a) Highest priority—those vital to the safe shutdown and isolation of the reactor, or whose failure could cause or increase the severity of a loss-of-coolant accident or result in release of excessive amounts of radioactivity.

(b) Second priority—those important to reactor operation, but not essential to the situations described in (a)

(c) Lowest priority—those not related to reactor safety or essential to reactor operation.

In the event that the AEC requirements for quality assurance become more stringent than the present General Design Criteria, future design and construction may be following standards and codes which increase nuclear plant costs; any relaxation of standards with greater adherence to "learning" efforts by the industry may make nuclear plant costs more competitive.

Quality can only be assured if properly written specifications (as defined by regulatory criteria, standards and good design practice) are followed by manufacturers, contractors, and owners. To this end, many manufacturers have developed quality assurance plans which have the fundamental function of using quality control personnel, facilities, and methods to check independently that specifications are met by fabrication and construction groups. Specifications may also be written by utility owners to assure their obtaining a component or system that meets their special requirements.

Current regulations require inspection of certain high priority components at stated intervals after plant start-up. The difficulty of making such inspections can have a profound effect on nuclear economics due to increased maintenance cost and lower plant availability. On-line inspectability provisions and off-line inspection procedures are being considered by all reactor manufacturers in the design of major reactor equipment.

It is important to note that reactor designers today are increasingly aware of the need to provide nuclear plant designs that can be inspected and tested.

Regulation

Plant Licensing

Construction and operation of nuclear plants is regulated by the U.S. Atomic Energy Commission through the licensing process. The applicable rules and procedures are published in the Federal Register, Title 10, Code of Federal Regulations. There are three major phases in the program:

1. *Construction Permit.*—A review is made of the proposed site with regard to proximity of population centers, topography, meteorology, hydrology, seismology, and geology, as well as preliminary design information for the facility. This is embodied in the Preliminary Safety Analysis Report, which is reviewed by the AEC Staff, the Advisory Committee on Reactor Safeguards, and the Atomic Safety Licensing Board at a public hearing. In 1969, the time required for this procedure averaged about 12 to 13 months, and a number of utilities now report a requirement of as much as 24 months or more. Also additional time is now required for the filing and processing of environmental impact statements for every proposed project. These statements set forth the environmental effects, the alternate approaches considered, the justification for the proposed facility, and other related information. Plant construction may not begin before issuance of the Construction Permit unless special permission is granted.
2. *Provisional Operating License.*—While construction is underway, detailed design information is developed; research and de-

velopment is carried out; standards, codes, and quality control procedures are applied; instruments and controls are installed; and operating and maintenance procedures are developed—all with the objective of insuring that the plant will be built and operated in a safe manner. On completion of plant design, this information is submitted in the Final Safety Analysis Report to the AEC.

3. *Operating License.*—Following further review with the Staff and the Advisory Committee on Reactor Safeguards, including presentation of evidence that the plant has been constructed as described, and pursuant to a public hearing if public opposition makes such a hearing advisable, an Operating License is issued. Under new AEC procedure, this Operating License would be good for the expected life of the plant if the intention of the AEC to issue the license or hold a hearing regarding it had been published in the Federal Register after March 30, 1970. In the case of nuclear plants where the AEC had taken this step on or before March 30, 1970, the procedure is to issue a Provisional Operating License first, which is in force for 18 months, or longer if extended. If a provisional license is issued, an operating license for forty years or less may be obtained after experience has been gained in operating the plant and routine operation is established.

The developing nuclear industry has been accompanied by changes in plant systems and safety requirements which have occasioned a detailed review of each facility application. The AEC and industry are working together to simplify the licensing review without detracting from its thoroughness. It is expected that standardization, the use of prelicensing reviews of new systems or basic changes, the development of an increasing number of codes and standards, the utilization of experienced personnel, and the development of further guidelines by the AEC with reference to design, performance, and safety criteria will result in expediting the licensing process.

The licensing requirements for the fast breeder reactor are expected to follow a similar pattern to that of the light water reactor. The early plants will require lengthy review periods which will gradually shorten as experience is gained and additional units are placed in service.

The Compliance Division of the AEC monitors the construction and operation of all licensed nuclear plants. During the periodic visits of the compliance inspector, records are examined and operations are reviewed to ascertain that they have been conducted in accordance with the Technical Specifications. Deviations are noted and generally result in the submission of an official report reviewing the item and detailing the plans to prevent a reoccurrence.

The safety record of the commercial nuclear power industry has been excellent to date, due in part to the strict licensing requirements. Problems have developed in operation of certain plants, some of which have caused shutdown but the safeguards have prevented any member of the public from being subjected to radiation levels above permissible limits.

Nuclear plants are also subject to regulation by state and local authorities, primarily with regard to environmental and thermal aspects. Zoning, is a responsibility of local, state and Federal agencies, and radioactive wastes are disposed of under regulations established and enforced by the AEC.

Technical Specifications

Technical Specifications are incorporated as part of the operating license and include those items which are considered important in providing reasonable assurance that the facility will be constructed and operated without undue hazard to the public health and safety. Included therein are descriptions of significant design features, operating procedures and limitations, and the frequency for conducting specific tests. The Technical Specifications thus serve to define the operating boundary limits.

Since the ultimate responsibility for the safe operation of the nuclear plant rests with the utility, it is given the appropriate authority, flexibility, and control over the operation of the plant, but such operation must be within the boundaries set up by the Technical Specifications.

If through operating experience it becomes desirable to modify the specifications, they may be amended by submitting to the AEC the requested revision together with a supporting safety analysis. A similar procedure is followed if design changes are made to the facility which require the specifications to be modified.

Operator Licensing

The regulations of the AEC specify the licensing requirements for personnel operating a licensed

nuclear facility. Two grades of licenses are issued—Operator and Senior Operator. Only a Licensed Operator can manipulate the controls of a reactor, and a Senior Operator is generally required to be at the facility at all times.

The licensing examinations are given by the AEC and consist of a written and an oral part. The examinations cover the area of nuclear fundamentals, plant design and systems, operation, and emergency procedures. They require a knowledge of the operating limits and Technical Specifications as well as the function of the various alarms provided in the control area. The subjects of radiation protection, waste disposal and plant chemistry are also covered. In general, all questions relate to the facility for which the license is sought. The oral portion consists of operating demonstrations, including manipulation of the reactor controls during a plant start-up and questions while on a plant tour.

For a new plant, licensing at a similar facility is generally a prerequisite. In the event of failure in the initial examination, reexamination may be given at intervals stated in the regulations. An applicant for a Senior Operator's License must answer additional examination questions over those given to an applicant for an Operator's License. The added questions require a more thorough knowledge of the subject matter as well as covering areas related to reports and administration. A satisfactory physical examination is required for both grades of licenses. The licenses are in force for a period of two years and must be renewed. To date, written and oral examinations have generally been waived for renewal applicants after a review of the utilization of the existing license and a recommendation by the plant manager that the applicant is qualified.

Nuclear Insurance

The Price-Anderson Act of 1954 requires a utility owning a nuclear power plant to carry a stated amount of liability insurance against the risk of personal injury or porperty damage off the site resulting from operations. The private insurance industry has provided a limit of $82,000,000, and the Federal Government has provided the remainder to a total limit of $560,000,000. The annual premium for nuclear liability insurance will vary with the type, size and plant location, but for a 1,000 mw reactor in a semi-rural area it will amount to about $300,000 per year. In addition, the costs of the Federal indemnity amount to an annual charge of $30/mw thermal. The Price-Anderson Act expires in 1977, and insurance requirements beyond that date cannot be predicted. The nuclear liability insurance does not relieve the facility operator of the responsibility for personal injury and property damage arising out of non-nuclear accidents. Therefore, conventional liability insurance of the type now utilized at fossil-fueled and hydro-electric plants would still be provided. In addition, since conventional insurance today will not indemnify the facility operator for damage to the facility itself for fire or explosion damage, for machinery breakdown, or for any other physical damage, he must provide nuclear property insurance for damage to the on-site property. Premiums for such insurance, which will protect against substantially all risks of physical damage, are conservatively three to four times higher than those prevailing for fossil-fueled or hydro-electric plants. The present limit available from the world-wide private insurance market is about $100,000,000; this is adequate for single-unit installations, but will fall short of total coverage of multi-unit plants now under construction. If the present favorable loss record continues, the insurance industry can be expected to provide increasing coverage at reduced costs.

Environment

As indicated in the Section on Regulation, the environment of a nuclear plant site is one of the factors considered by regulatory agencies in determining if a license will be granted. Safety of the public is the primary concern, but other aspects of the environment also will have an influence on the design and operation of a nuclear plant.

Since nuclear fuel has a low transportation cost, a plant can be located with little regard to this factor. Thus, the most advantageous location for a nuclear plant is near the load center. However, thus far, most plants have been located some distance from population centers and consequently from load centers, requiring high capacity transmission lines for which it is difficult to obtain rights-of-way in heavily populated areas. It is expected that as more experience is gained with nuclear plants they will be permitted closer to population and load centers. However, as population densities continue to increase, securing suitable sites for plant construction and transmission will be difficult problems.

A nuclear plant must have suitable access routes

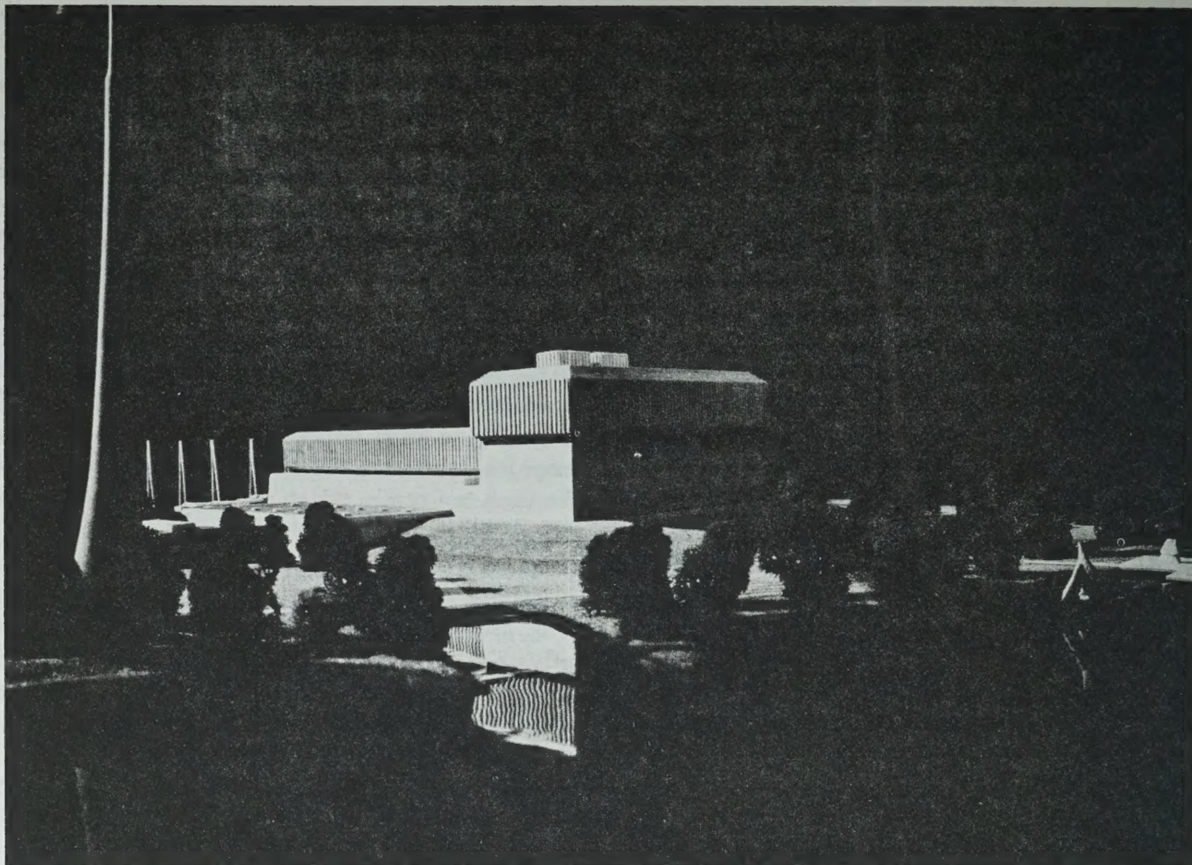


FIGURE 25.—TVA's Browns Ferry nuclear power plant being built at a site on the north shore of Wheeler Lake in Limestone County, Alabama. Each of the three generating units which utilize boiling water reactors will have a rated capacity of 1,152 megawatts.

to permit movement of large and heavy components during construction and refueling. This may be a heavy duty highway, railroad, or water barge route. The reactor vessel usually is the largest piece to be handled and in the past has usually been moved by a combination of routes. On-site fabrication of these vessels has been developed, resulting in freedom from this requirement in the future.

An adequate source of cooling water is essential to any plant site, fossil or nuclear, but because the efficiency of present nuclear cycles is lower than for fossil plants, about 50 percent more heat is rejected to the condenser circulating water. The potential effect of this heat on aquatic life in the vicinity is resulting in more stringent regulation of heated water discharge to surface streams. As discussed in Chapter I, measures that can be taken to comply include cooling ponds and cooling towers, which may be wet or dry, natural or mechanical draft. Any such measures of course will carry an economic penalty, and the choice requires extensive evaluation.

The quantity of gaseous effluents from a nuclear plant is insignificant compared to the amount from a fossil plant of equivalent rating. However, because of high specific activity, releases from nuclear plants are closely regulated. Radioactive gases can be held up for relatively short periods of time, a few minutes to a few months, to permit the isotopes to decay to an insignificant level, after which they can be released to the atmosphere under conditions that will give maximum dilution.

Liquid wastes can be processed by filtration, ion exchange, or other processes to remove longer-lived isotopes from the liquids, which then have low enough activity to permit discharging to the environment with the condenser circulating water.

Liquid and gaseous discharges from nuclear plants are carefully regulated in the plant licensing requirements, and therefore will have a minimum effect on the environment.

The appearance of electric generating stations can be expected to become more important, especially in urban areas where public awareness of esthetic values is increasing. In this regard, nuclear

plants have a distinct advantage over fossil fueled plants with their freedom from coal and ash piles, and handling equipment. Nuclear plants lend themselves to better architectural treatment to present a more pleasing appearance, and even the containment structure can be given graceful lines. This factor should aid considerably in increasing acceptance of urban siting of nuclear plants in the future.

In determining the acceptability of a proposed site for a nuclear plant, the AEC considers various environmental factors. The population density is determined at varying distances from the plant and is evaluated in light of the capacity and type of the proposed installation as well as the containment system and engineered safety features to be employed. Since severe earthquakes might cause extensive damage to inadequately designed structures, the seismology and geology of the site area are thoroughly investigated. The plant design must be adequate to withstand the surface faulting and vibratory motion resulting from the effects of the largest earthquake potentially expected in the given area. The hydrology of the proposed site is also investigated, and the plant design must incorporate safety features to make it capable of withstanding the effects of extreme flooding as well as the loss of cooling water resulting from the failure of downstream dams. For coastal sites, tidal waves must be considered. Meteorology also plays a role in the site consideration as wind and weather patterns must be factored into the analysis supporting the permissible release rate for gaseous effluents.

Present Research and Development Effort

The research and development effort required to bring nuclear power to the present state of acceptance and use has involved investigation, in depth, of:

a. Various combinations and configurations of potential nuclear fuel materials.
b. Fuel preparation and management, including "used" fuel reprocessing for reclamation and future sale or reuse of valuable "unburned" or "bred" constituents.
c. Reactor components
d. Nuclear plant instrumentation and controls
e. Coolants
f. Other areas of technology and material development leading to increased efficiency, safety, and economy of nuclear plant operations.

Each reactor concept has required research and development peculiar to that concept. Several different reactor concepts have been examined over the years and discarded, or their further development has been deferred for technical or economic reasons. R & D for other reactor concepts has been more successful and those concepts have been more fully developed, e.g. light water (boiling or pressurized) thermal reactors and gas-cooled reactors.

Light Water Reactors

Manufacturers now are able to shop-fabricate pressure vessels and other components for nuclear power plants approaching ratings of 1,500 mw. This is an important factor in the trend to the larger, more economic plants. Improvements in plant components, reactor control, and data obtained from power plant operation have made it possible to increase core power density. Safety features, including engineered safeguards systems, have been improved. Improvements are being made in the amount of useful energy obtained from water reactor fuels before processing.

Despite the status and projected advances in light water reactors, there remain some reservations about the state of the technology. No plants have operated in the larger sizes which are being committed. Although there is little experience with nuclear fuel at the radiation exposures which are being contemplated for the new commercial plants, experience is rapidly being accumulated. Continued improvement of the pressurized and boiling light water reactors is now the responsibility of industrial suppliers and the electric utilities. AEC support of light water reactor development will be limited to activities in the main related to plant safety and to the support of improvement of fuel resource utilization such as plutonium recycle in light water reactors.

The AEC support for plutonium recycle work for thermal reactors is being decreased with the expectation that the industry will increase its research and development programs to make plutonium recycle an effective part of the nuclear power system. Phase-out of the Commission recycle program is planned for 1971.

Advanced Converter and Low Gain Breeder Concepts

There has been some interest in so-called advanced converter and low gain breeder reactor concepts because of their promise of better eco-

nomics and higher conversion ratios than the pressurized or boiling light water reactors.

U.S. effort to develop advanced converters has been narrowed to two approaches, the high temperature gas-cooled concept and the seed-blanket light water breeder concept. The principal technical objectives have been to: (1) introduce into the growing nuclear industry advanced and improved technology with attendant cost reductions in producing energy; (2) reduce the requirements of fissile fuel materials to extend the availability of nuclear resources; and (3) permit the use of high cost nuclear fuel resources while still producing low cost energy, thereby expanding the resource base.

1. *Light Water Breeder*

With regard to the Light Water Breeder Reactor (LWBR), fabrication has begun on a reactor core. The thorium-uranium 233 seed-blanket Light water Breeder Reactor concept has an expected conversion or breeding ratio high enough to increase the fuel utilization significantly beyond that of present types of light water reactors or ad vanced converters currently in the AEC program. Successful development of the LWBR would make available for power production about 50 percent of the potential energy in the thorium fuel resources.

The breeding gain expected in the LWBR concept is not as great as that potentially obtainable using plutonium fast breeder systems, and the system would not produce the excess of fissile material over that consumed which would make possible the fueling of additional reactor capacity from bred fissile material. On the other hand, the LWBR is based on proven pressurized light water reactor technology and, except for changes in the reactor core, does not require a significant departure from the technology on which the growth of the U.S. nuclear utility industry is at present dependent. The LWBR therefore has few engineering development uncertainties in the plant and can provide a system of proved practicality and comparable reliability along with substantial improvement in fuel utilization over present types of light water reactors. With the engineering status in a relatively favorable condition, the major long-term problems on seed-blanket light water breeder acceptance may center on the economics of core fabrication and fuel cycle costs. Successful completion of a breeding demonstration would show that it is technically feasible to install breeder cores in existing and future pressurized light water reactor plants.

The LWBR research and development program includes large scale physics, critical experiments using uranium 233 and thorium, reactor component development and engineering tests, fuel element development, irradiation testing, and analysis.

2. *High Temperature Gas-Cooled Reactor*

The High Temperature Gas-Cooled Reactor (HTGR) system is a helium cooled graphite moderated concept with a potential for lower power costs and higher conversion ratios than present light water reactors. Large HTGR plant designs use the thorium fuel cycle; the initial fuel loadings use uranium 235, but after about seven years the core loadings would be primarily recycle uranium 233 with only small additions of uranium 235.

In the United States, commercial development of gas-cooled reactors has centered on Philadelphia Electric Company's 40 mw Peach Bottom Atomic Power Station at Delta, Pa., which went into commercial operation in 1967. This plant has served as the forerunner of a 330 mw Fort St. Vrain HTGR being built at Platteville, Colorado by Public Service of Colorado. The PSC reactor will use improved thorium-urainum coated particles. The reactor will be cooled with 700 psia helium and will be designed to produce steam at 2,400 psi and 1,000°F with a 39 percent net plant thermal efficiency. A prestressed concrete reactor vessel will house the entire primary system, including the core, the steam driven axial-flow helium circulators, and the steam generators which are located under the core. Research and development and design were initiated in July, 1965. Commercial operation of the plant is expected to be attained by 1972.

As a result of R & D, a greater understanding of the problems involved in using graphites as a high temperature reactor material has been reached. Analytical methods developed for the reactor physics of high temperature graphite cores have been confirmed through operation of the Peach Bottom reactor. The advent of the prestressed concrete technology for large reactor vessels provides new possibilities for the HTGR concept. Plant components for large HTGR's will differ substantially from those used in Peach Bottom. Important plant and component design changes are dictated by the use of a prestressed concrete reactor vessel, increased component size, different safety and containment concepts, and the required high degree of plant performance, reliability and maintainability. The new components require development and testing. Leakages of helium, lubricating fluids and steam will require careful control, and systems and

special instruments to achieve this control will be developed. The initial development efforts on demonstration components and systems for large HTGR power plants will be provided by the Fort St. Vrain station.

Research and development efforts for high temperature gas-cooled reactors have included such areas as nuclear safety analysis, fuel development, prestressed concrete pressure vessels, containment and related safety features, and component development, including turbine-driven circulators, control rod drives, steam generators, and fuel handling machines. Fuel recycle studies include fuel reprocessing, fabrication, handling and related safety implications.

Fast Breeder Reactors

The available reserves of uranium and thorium contain almost unlimited amounts of latent energy that can be tapped, provided "breeder" reactors are developed. Successfully done, this will render relatively unimportant the cost of nuclear raw materials so that even very low grade sources will become economically acceptable. The relative insensitivity of high gain breeders to ore prices will also make usable the large amounts of uranium available from higher cost ores. The development of high gain breeders will increase fuel utilization from the few percent potentially usable in present day reactors to over 50 percent. The energy that can be extracted from the low cost ores will thereby be extended by factors of 10 to 30. High gain breeders will also produce an excess of fissile material over that initially present, which can be used to fuel new reactors in an expanding power system. The fast breeder with its potential for matching the doubling time of the electric industry can most efficiently use the fertile uranium 238 in depleted and natural uranium.

The fast breeders of major interest are divided into two categories—sodium cooled and gas cooled. The sodium cooled fast breeder concept has been selected for development in a first priority program on the basis of potential economy, reactor manufacturer interest, and technological experience gained in the U.S. and abroad. This concept has been selected for development by the United Kingdom, France, Germany, Japan, and the U.S.S.R. and is receiving attention in other countries.

1. *Liquid Metal Fast Breeder Reactor* (*LMFBR*)

The Liquid Metal-Cooled Fast Breeder Reactor (LMFBR) concept using sodium as the coolant dates from 1945. Sodium was chosen primarily because it has a combination of good nuclear characteristics which help in attaining high breeding ratios, with potential doubling times of eight to ten years. Also it has a high boiling point which permits high temperature and low pressure operation, with resultant high plant thermal efficiency and thin primary wall structures. Furthermore, it has excellent capability for transferring heat; has a large heat capacity, which allows for remedial action in the event of a power transient or loss of coolant flow; requires low pumping power; and has relative freedom from corrosion in the absence of air and water. Sodium as a coolant has disadvantages associated with its prolonged radioactivity after reactor shutdown—its chemical reaction with air and water, its nontransparency and solidification—which make maintenance difficult.

LMFBR Program Plan

The objective of the LMFBR program is to achieve, through research and development, the technology which will make possible the design, construction, and operation of safe, reliable, and economic fast breeder reactors in central station nuclear power plants.

The AEC has had a limited experimental development program for fast breeder reactors for many years. Moving such a general program to the forefront of the national reactor development effort required several major steps. One of the first steps was the preparation of the LMFBR Program Plan composed of an overall plan and detailed plans for each of nine specific technical program areas: plant design, components, instrumentation and control, sodium technology, core design, fuels and materials, fuel recycle, physics, and safety.

The total R & D program effort will further identify the key research and development problems, provide conceptual plant designs, determine the role of demonstration plants in the research and development program, select methods for developing engineering capability in the industrial complex, determine the amount and allocation of resources required, and determine the priorities and schedules for each segment of the program necessary to develop commercial plants.

Special facilities are needed for the LMFBR R & D effort. For example, LMFBR component testing and evaluation will be conducted in a test installation, the Liquid Metal Engineering Center (LMEC), at Canoga Park, California. LMEC is a complex of test facilities with supporting chemical, metallurgical, and instrumentation laboratories for testing and evaluating instruments, equipment,

and components such as steam generators, valves, pumps, and flow meters for fast breeder reactors.

An experimental reactor, Experimental Breeder Reactor No. 2, at the National Reactor Testing Station (NRTS) in Idaho is being used as a fast flux test facility for irradiating fuels and materials for the LMFBR program. Greater and more versatile test capability will be provided by the 400 mwt Fast Flux Test Facility (FFTF) scheduled to be in operation near Richland, Washington in 1974. The FFTF is to have a fast neutron flux, temperature, and coolant environment typical of that expected in commercial fast breeder reactors, and will be the major fuels and materials test irradiation facility in the LMFBR program. The successful development of nuclear fuel that can withstand the high burnups (approaching 100,000 MWD/T) required for economic operation of the fast breeders will, in a large measure, be dependent on the FFTF. Full statistical confirmation of high fuel burnup capability will be achieved in the demonstration plants.

Fast breeder reactor physics data are essential to the design and operation of safe and economic fast breeder reactors. Four zero power reactors will provide accurate nuclear data for use in reactor core criticality and safety studies and for economic analyses of reactor cores.

Several significant factors must be considered in establishing the safety of the LMFBR. Among these are the short neutron lifetime, the small delayed neutron fraction associated with plutonium, the hypothetically possible critical reassembly of the fuel in the event of core meltdown, the possibility of increased reactivity from void formation in the sodium; and the possibility of chemical reactions of sodium with air and water. The LMFBR safety program is being oriented to provide the research and to develop the components and systems necessary to resolve the many problems associated with these factors. The program includes operation of fuel, components, systems and instruments in sodium at temperatures up to 1,200°F, and exposure to the sodium cover gas which is saturated with sodium vapor and in the presence of impurities in the sodium and sodium vapor. The role of impurities in the sodium is being investigated in relation to sodium heat transfer; fluid dynamics; chemistry; analysis, monitoring, and purification of sodium; and the effects and control of sodium-air and sodium-water reactions. Analytical procedures, purification methods, and detection systems are being developed based on these investigations.

Design studies of 1,000 mw LMFBR plants have been undertaken by five industrial contractors. The identification of the research and development programs required for detailed design and construction of safe, reliable, and economic 1,000 mw LMFBR plants for the 1980's will continue. Evaluation of designs and the research and development programs that will be required is underway, and more in-depth plant design studies are being assigned to several AEC contractors. The studies will help to provide a basis for the design of demonstration plants which will be essential in validating the results of the overall research and development program, in strengthening the industrial base, and in obtaining early acceptance of the plant types by utilities. Recent growing awareness of the need for fast reactor development has led to the formation of at least three utility industry-reactor manufacturer study groups. The objectives of these programs are to provide design, construction, licensing, and operating experience necessary to ensure the ultimate success of commercially sized breeder reactors.

The commitments to build the demonstration plants will depend upon an assessment of the technological and engineering uncertainties, the economics, the financial risks, and the willingness of reactor manufacturers, utilities and the AEC to participate in and to accept the projects and the risks involved. Utility acceptance will be contingent on developed technology, on the existence of a competitive and self-sustaining industry, and on a minimum investment of risk capital.

The AEC, in May, 1969, initiated the first phase of a two-phase program for the first LMFBR demonstration plant. This first phase, called the Project Definition Phase, is expected to lead to a contractual arrangement for the design, supporting R & D, construction and operation of a LMFBR demonstration plant. The five reactor manufacturers who have declared their intention of proceeding on a commercial basis with LMFBR's were invited to submit proposals relating to the first phase. Proposals were received from three reactor manufacturer/utility teams, and contracts were subsequently negotiated with each team for the first phase work. Upon completion of the first phase, one of the three contractors will be selected to enter into a definite contractual arrangement for construction of the plant. It is anticipated that the Demonstration Plant Program will result in the construction of three demonstration plants in the 300–500 mw range at intervals of about two years with the first plant to begin operation in 1977.

The plants would be owned and operated by

utilities. It is expected that a significant amount of AEC financial support and involvement will be necessary to meet the objectives of this effort. It is further expected that the reactor manufacturer/utility teams involved would follow through with subsequent large scale investment to support the development efforts necessary for the large commercial LMFBR plants to sizes up to 1,000 mw, a few of which might require modest AEC assistance.

2. *Gas Cooled Fast Breeder Reactor* (*GCFR*)

The gas (helium) cooled fast breeder promises a combination of advantageous characteristics which make it an attractive breeder. It has good neutron economy, with doubling times approaching those of the LMFBR, and high temperature operation with high plant efficiency. Maintenance is facilitated by low coolant radioactivity and by the fact that the coolant is transparent and chemically inert. Coolant void reactivity and materials compatibility problems are minimal. Its disadvantages include difficulty of emergency cooling, stringent limitations on steam and helium leaks, use of relatively high pressure, and high pumping power.

The GCFR differs from the High Temperature Gas Cooled Reactor primarily in that no moderator is required and the fuel element consists of small diameter metal clad ceramic fuel pins. Its fuel is much like the LMFBR if provisions are made for equalizing the pressure across the cladding. The requirements and provisions for the emergency cooling system in the event of a loss of coolant accident are significantly more stringent than for the HTGR, because of the higher power density and the lower overall heat capacity of the system.

In current conceptual designs of the GCFR, the reactor and steam generators are contained in a prestressed concrete reactor vessel which also serves as the biological shield. The primary system is also enclosed within a steel-lined concrete containment building. Electricity is generated from a high pressure steam cycle with a new plant thermal efficiency of about 40 percent. The steam generators are supplied with 1,250 psi high temperature helium from the reactor. Conceptual design work was undertaken by the Commission in 1963. More recently, industry has completed conceptual design studies to establish the practicality of a 1,000 mw plant, and 37 utility companies are supporting a design study on a 330 mw demonstration GCFR plant.

General Reactor Technology

The general reactor technology programs, conducted in industrial, university, and AEC laboratories, comprise the applied research and development activities needed to generate the technological base underlying the initiation and accomplishment of specific reactor programs and projects, to resolve critical problems, and to continually assess programs and projects. General reactor technology programs are needed to open up new areas of technology upon which future advances may be based. Therefore, the AEC carries out a general reactor technology program on nuclear fuels and materials, reactor physics, heat transfer and fluid dynamics, and reactor and process instrumentation. A report on selected general reactor technology activities is published annually.

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CHAPTER III

HYDROELECTRIC AND PUMPED STORAGE GENERATION

Summary

Although most available sites for economical production of hydroelectric energy have been developed, some additional hydro capacity will be provided at new sites, or by additions at existing plants. The movement of hydroelectric power into the peak of the load is bolstering project power benefits, and is permitting consideration of many possibilities which formerly were marginal or uneconomical under higher capacity factor standards. After 1965 the size of generating units increased dramatically and units as large as 600 megawatts capacity each are being manufactured in the United States for installation in the Grand Coulee Plant in the State of Washington.

In many cases the development of hydroelectric power provides such associated benefits as recreation, water supply, fish and wildlife enhancement, flood control, and cooling water for thermal-electric and industrial plants. These multipurpose benefits allow many projects to be developed that would not be economically justified as single purpose projects. The favorable characteristics of hydroelectric power and the frequent multiple use benefits associated with its development provide strong incentives for utilizing the remaining potential of our water power resources that can be developed economically.

It is anticipated that pumped storage will be the major component of new hydro construction in the United States, and that the extent of its future development will be limited only by the availability of suitable sites and a dependable supply of economical pumping energy. The use of pumped storage has increased rapidly from 677 megawatts in 1963 to more than 9,000 megawatts operating or under construction by 1969.

Where the above requirements are fulfilled, pumped-storage generation can be economically attractive under present conditions; it is likely to become even more so in the future as the proportion of nuclear capacity in service increases. The flexibility of operation of a pumped storage plant in meeting sudden load changes and its ability to provide high-inertia spinning reserve at low operating cost are additional benefits that can weigh heavily in favor of this type of installation.

Conventional Hydroelectric Generation

Introduction

Conventional hydroelectric developments convert the energy of natural or regulated streamflows falling through heads created by dams and waterways to produce electric power. Such plants may be classified as run-of-river or storage projects by the manner in which available streamflow is utilized, and may be distinguished from pumped storage projects in that water comes to the plant as a result of natural means unaffected by artificial mechanical means such as water pumping.

Conventional hydroelectric as distinguished from pumped storage at the end of 1969 accounted for about 15.8 percent of all the electrical generating capacity in the U.S. and this proportion is declining as the remaining available sites become developed and other types of generation are expanded rapidly. Conventional hydro may be used for either peaking or base load generation, depending on plant design, system requirements and prevailing conditions of water supply. However, due to increasing value of the use of hydro for peaking power as a result of the need for thermal plants to supply larger and larger percentages of the energy component of the total power load, it may be expected that most of the existing and future hydro plants will be used predominantly to serve peaking power requirements.

Characteristics

Hydroelectric power is unique among basic electric energy sources in that it does not require fuel for generation. The recurring cycles of rainfall,

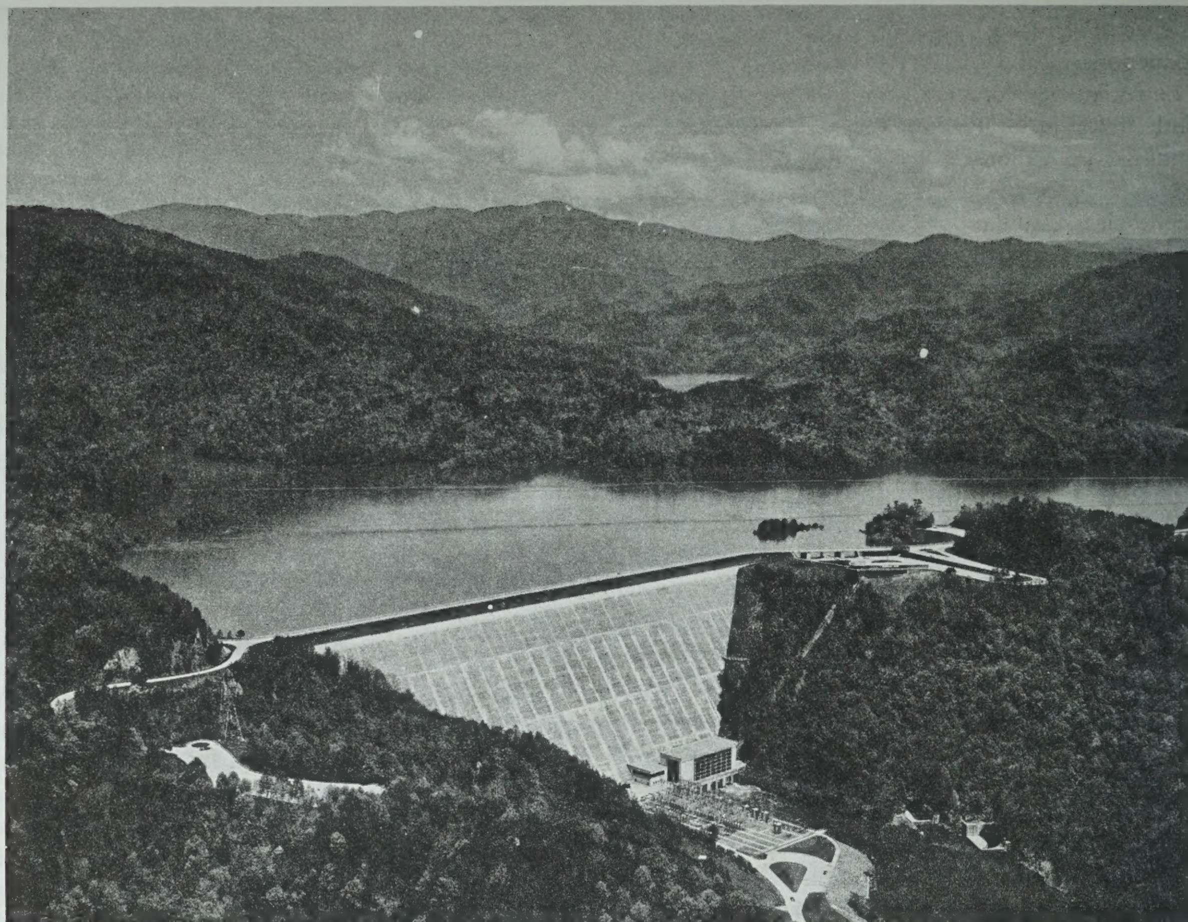


FIGURE 26.—TVA's Fontana Dam (three units with a total capacity of 202,500 kw). The reservoir has a useful storage of 1,157,300 acre feet used for flood control, navigation, and power production.

runoff, evaporation and transpiration make hydroelectric power a renewable energy resource.

The amount of capacity which is installed in a hydroelectric plant and the manner in which it is utilized depend upon a number of factors. These include the available head and streamflow, reservoir storage capacity, and operating limitations imposed in the interest of other water uses. The amount of capacity installed may also be limited by the load to be served in the area within economical transmission distance. Frequently, an initial power installation is made and provisions are included in the project's design for the installation of additional generating units when warranted by increased loads. In many instances adequate provisions have not been made for expansion of plant capacity to serve the peaks of expanded system loads.

At any potential hydroelectric site, available head is one of the basic design parameters which usually determines the type of turbine to be installed. Four types of hydraulic turbines are currently in use. The Pelton impulse-type turbine with a vertical or horizontal axis directly connected to generator is extensively used at sites where heads above 1,000 feet are available. The Francis reaction-type turbine is usually favored for heads in the range of 1,000 to 100 feet, however, the Francis turbine can be efficiently used with heads above 1,000 feet. After 1965 the size of Francis units increased dramatically, and the third powerhouse now under construction at Grand Coulee Dam in Washington is employing units with a capability of about 600 megawatts each coupled to a Francis runner of about 820,000 horsepower. Fixed-propeller-type turbines, or adjustable blade turbines, known as Kaplan units, are usually used where heads are less than 100 feet. Francis and Kaplan turbines are normally designed with vertical axes. Recent reevaluation of new and existing hydroelectric sites having heads in the 15 to 35 foot range has led to the development of the horizontal axial-flow bulb or tubular turbine. These turbines are sometimes connected to the generator through

a speed-increasing train of gears which permits reductions in the size and cost of the generator. The recent development of mixed-flow turbines of both the adjustable pitch and fixed-pitch type is finding application for heads ranging from about 80 to 250 feet. These turbines provide a more economical installation over their applicable head range than Francis turbines because of their higher operating speeds.

Hydraulic turbines are sized and designed to operate near their best efficiencies under average head conditions.

Some projects, such as those on the Niagara and St. Lawrence rivers, have been designed to operate as baseload plants and others, principally in the Pacific Northwest, provide nearly all of the power to meet total load requirements. Usually, however, hydroelectric developments are designed to operate largely during the hours of peak power loads. The annual cost of providing peaking capacity by installing additional units in hydroelectric plants is less, in many cases, than the cost of additional capacity from alternative sources. Other characteristics of hydroelectric units as discussed later often enable them to complement thermal-electric plants which can be operated to serve the base load portions of the loads. Hydroelectric plants having seasonal or annual storage may have their operations scheduled to serve loads primarily during only the months of peak kilowatt demands on the system. Plants having only sufficient pondage for daily or weekly operations are used daily during the hours of peak load.

Capital and Operating Costs

The investment in hydroelectric projects per kilowatt or installed capacity varies greatly according to the type of project, its size and location, the cost of lands required, and the cost of relocations of highways, railroads, buildings and other improvements. The capital costs of powerhouse and equipment per unit of installed capacity decrease with an increase in operating head. For example, the cost per kilowatt for powerhouse and equipment with an installation of 100,000 kilowatts operating under a 100-foot head is estimated at $130, compared to about $90 for a plant of comparable size operating under a 400-foot head. This relationship, therefore, is a contributing factor to the possibility that development of certain river reaches for power by a single high dam may be more economical than by two or more lower dams. The unit cost of an installation at a particular site is less if large capacity units are installed rather than more units of smaller size. Operating costs also decrease with increased head and unit size, and further, where feasible, by use of automatic or remote supervisory control.

On the average, excluding pumped storage, the investment cost per kilowatt is substantially higher for hydroelectric plants than for thermal-electric plants. The capital cost of hydroelectric plants usually varies between $200 and $400 per kilowatt of installed capacity. On the other hand, hydroelectric plant operating expenses are much lower, principally because no fuel is required and other operating and maintenance costs are less. The best of our hydroelectric developments provide the lowest cost power in the nation.

Table III–1 lists the capital cost of a few selected conventional hydroelectric projects completed in recent years. No Federal projects were included in the table as they are multipurpose projects and their cost would not be comparable.

An increasing number of hydroelectric projects are being equipped for remote control to reduce operating costs.

Economies are being realized through improvements in design and construction of dams.

Major advances have been made in techniques and equipment used in tunneling and underground excavation. Under suitable situations underground powerhouses are proving to be economical and satisfactory.

Generally, investment and operating costs per kilowatt for power plant, waterways, and equipment can be decreased through the installation of large units.

Hydroelectric generating units of high efficiency have been designed and built for many years. Most hydraulic turbines are capable of operating at efficiencies of 90 percent or better, and thus produce electric energy more efficiently than any other means of mass energy production.

Advantages and Disadvantages, Evaluation and Use

Hydroelectric plants have several important advantages over thermal plants. They neither consume water nor do they heat the water of rivers and streams as thermal plants do, and hydroelectric plants do not contribute to air pollution.

Because of their ability to start quickly and make rapid changes in power output, they are particularly well adapted for serving peak loads and for assisting in the supply of spinning reserve. If oper-

TABLE III–1

Capital Cost of Typical Conventional Hydro Projects

Owner	Name of plant	Capacity (MW)	Head (Ft.)	In-service Date	Cost of Plant (in thousands of dollars)						Cost/kW	State
					Land	Structures	Reservoirs dams, etc.	Equipment	Roads and trails	Total		
PRIVATELY OWNED												
Central Maine Power Co.	Indian Pond	76.4	145	1954	$ 738	$2,608	$ 7,175	$ 4,739	$ 371	$15,631	$208	Maine
New England Power Co.	Moore	140.4	150	1956	2,524	2,970	16,582	7,529	......	29,605	211	N.H.
Virginia Electric & Power Co.	Gaston	177.9	67	1963	7,724	1,797	24,195	9,957	53	43,726	246	N.C.
Do.	Roanoke Rapids	100.1	75	1955	1,463	1,962	20,606	6,499	68	30,598	306	N.C.
Tapoco, Inc. (Aluminum Co. of America)	Chilhowee	50.0	57	1957	2,234	417	5,346	3,567	33	11,597	232	Tenn.
Alabama Power Co.	Bouldin	225.0	117	1967	6,084	5,502	18,986	8,448	11	39,031	173	Ala.
Do.	Lay	177.0	81	1967	7,643	1,387	17,357	10,387	......	36,774	208	Ala.
Montana Power Co.	Cochrane	48.0	80	1958	59	983	5,379	3,904	82	10,407	217	Mont.
Idaho Power Co.	Hells Canyon	391.5	210	1967	1,131	2,278	51,507	10,893	......	65,809	168	Idaho
Do.	Oxbow	190.0	115	1961	197	7,073	28,326	10,516	10	46,122	243	Idaho
Do.	Brownlee	360.4	250	1958	11,671	6,059	39,148	11,638	......	68,517	190	Idaho
Pacific Power & Light Co.	Swift No. 1	204.0	350	1958	7,740	2,915	38,191	8,974	99	57,919	284	Wash.
Washington Water Power Co.	Cabnet Gorge	200.0	99	1952	7,375	7,548	16,195	12,524	823	44,465	222	Idaho
Do.	Noxon Rapids	282.9	152	1959	31,101	6,887	28,119	18,472	88	84,667	299	Mont.
Portland General Electric Co.	Pelton	108.0	150	1957	233	2,731	11,855	5,165	648	20,632	191	Ore.
Do.	Round Butte	247.1	315	1964	3,347	5,087	37,711	8,536	886	55,567	225	Ore.
Pacific Gas & Electric Co.	James B. Black	154.8	1,115	1965	3,660	1,779	50,324	5,009	1,084	61,856	399	Calif.
Southern California Edison Co.	Mammouth Pool	129.4	250	1960	161	1,626	17,857	6,388	520	26,552	205	Calif.
PUBLIC (NON-FEDERAL)												
City of Seattle	Boundry	551.0	250	1967	582	13,480	48,758	28,027	486	91,333	166	Wash.
Grand River Dam Authority	Kerr	108.0	58	1964	11,539	3,750	9,627	7,197	216	32,329	299	Okla.
PUD No. 1 of Chelan County	Rocky Reach	711.6	92	1961	41,291	54,667	63,382	46,779	191	206,310	290	Wash.
PUD No. 1 of Douglas County	Wells	774.3	65	1967	30,540	25,639	36,560	27,814	263	120,816	156	Wash.
Grand County PUD	Priest Rapids	788.5	78	1961	2,413	8,549	76,560	46,409	......	133,931	170	Wash.
Do.	Wanapum	831.3	80	1963	15,443	9,811	87,076	43,836	......	156,166	188	Wash.

ating at less-than-full load they are, in most cases, able to respond very rapidly to sudden demands for increased power. Their utility for supplying starting power to steam-electric plants following a major power failure has been demonstrated on several occasions in recent years.

The maintenance costs of hydroelectric plants are relatively low, and in many instances the plants can be designed for automatic or remote control operation. They have long life, low depreciation expenses, and relatively predictable costs, inasmuch as fixed charges are a much larger part and current operating expenses a much smaller share of total costs than in the cases of fuel-burning plants. The generating units are more reliable than steam-electric units because they operate at relatively low speeds and the turbines are not subjected to temperature stresses. A unit is normally out of service about two days per year because of forced outages and about one week for scheduled maintenance. This total outage rate of approximately three percent is about one-fourth that for modern steam-electric units. However, hydroelectric units are subject to types of capacity and energy reductions that do not affect thermal units, namely reductions due to decreased head and adverse streamflow conditions.

In many cases the development of hydroelectric power provides such associated benefits as recreation, water supply, fish and wildlife enhancement, flood control, and cooling water for thermal-electric and industrial plants. These multipurpose benefits allow many projects to be developed that would not be economically justified as single purpose projects. The favorable characteristics of hydroelectric power and the frequent multiple use benefits associated with its development provide strong incentives for utilizing the remaining potential of our water power resources that can be developed economically.

The disadvantages may include: high capital costs; remote locations, often far from centers of demand with consequent expense for long-distance transmission lines; dependence on variable stream flows and other natural factors beyond the control of man; operating restrictions imposed by competitive water uses; changes in scenic values, although this may be relative; adding nitrogen to the

water as a result of spillway operation; removing oxygen from water when stored in deep reservoirs; and increasing the temperature of water in shallow reservoirs.

Licensing

Development of a hydroelectric site is seldom undertaken solely for generation of electric power. The impounding of water in a river basin often results in many other social and economic benefits such as recreation, fish and wildlife enhancement, flood control, irrigation, improved water supply, water quality control and navigation.

The multipurpose aspects of river basin development are recognized in Section 10(a) of the Federal Power Act which requires that any hydroelectric project to be licensed must, in the judgment of the Commission, be best adapted to a comprehensive plan "for improving or developing a waterway or waterways for the use or benefit of interstate or foreign commerce, for the improvement and utilization of waterpower development, and for other beneficial public uses, including recreational purposes." Thus an important prerequisite to FPC licensing is the need to plan water resources projects—where hydroelectric power development is included to harmonize with the needs and demands of all water users. To meet these needs the Commission has under way a program of water resource appraisals. This program builds upon any useful water resource studies by others in developing an updated analysis of requirements and potential solutions.

Federal, State and local interests are becoming increasingly aware of the importance of planning for the comprehensive development and utilization of the Nation's water and related land resources. Most recent studies, and those now scheduled, provide for the cooperation of all interests. Despite the planning work that has been accomplished to date, a great deal of continuing additional study is needed.

Trends and Developments (1968–1990)

The most significant technological trends that reasonably can be anticipated are those toward larger units, suitable for new and redeveloped sites, possibly through water cooling of generator stators; higher specific speeds of turbines; and larger peaking installations at favorable project sites and lower plant capacity factors. All these trends point towards lower unit costs of capacity.

There will also be trends and developments in the following areas:

a. Downstream re-regulation of peak river flows.
b. Use of hydroelectric impoundments as source of cooling water for steam-electric plants.
c. Increasing usable capacity of hydro projects by addition of reversible pumping and generating units.
d. Widespread use of reservoirs for recreation.
e. More emphasis on esthetics in plant design including underground powerhouse.
f. Remote supervisory control of many hydro developments.
g. Prospects for increasing use of pumped storage as conventional hydro sites become scarce.

Countering these trends, however, are the facts that many of the lowest cost hydro sites have already been developed and that there appears to be growing public opposition to proposed hydro projects, based on claims that these projects and their associated transmission lines would (1) adversely affect the natural landscape and environment, (2) conflict with other water uses, and (3) encroach on land resources and economic developments.

Suggested Areas for Research and Development

Principal research and development efforts will be directed toward the following:

1. *Major items concerning plant, structures and equipment design*

   a. The production of larger units of equipment with high reliability—turbines, generators, transformers, breakers, etc.
   b. Methods of flood forecasting and means of increasing spill capacity of existing dams.
   c. Uplift pressures under gravity structures.
   d. Dam instrumentation with remote indication for maximum safety of the general public.
   e. Redevelopment of existing hydroplants for units of greater capability in existing settings.
   f. Wicket gate seal design.
   g. Adaptation of slant shaft propeller units and bulb type turbines for American installations.
   h. Down-stream water quality improvement with up-stream controls.
   i. Coordinated turbine and generator design to provide closer coupled, more compact units.

2. *Major Maintenance*

a. Alarm devices for failure of wicket gate shear pins. TVA has developed a simple alarm device for indicating failure of wicket gate shear pins based on air leakage from a hole drilled through center of each pin. This system is in service at the Fontana and Nickajack plants. A liquid dye system is used in a similar manner at the Salina Pumped Storage Project in Oklahoma.

b. Runner blade coatings to eliminate effects of cavitation on base metal. Also, underwater metal structure coatings producing longer structural life with minimum of maintenance.

c. Methods of air admission to turbines for cavitation control.

d. Methods of underwater concrete structure repair including deep-diving practices.

Pumped Storage Generation

Introduction

The installation of an increasing number of large base load thermal generating units which cannot be economically operated at low load factors has led to the planning and installation of generating capacity specifically suited to supply peak loads. One aspect of this trend has been the development of reversible pump turbines which can be used both for pumping and generating. These projects are ideal for peaking purposes because of low capital costs and the economies they introduce in the operation of systems with large thermal capacity.

Pumped storage capacity in the U.S. increased by more than 2,500 megawatts during the years 1963–1968. The total of such capacity was 677 megawatts in 1963. By 1968 this had increased to 3,233 megawatts actually operating; 3,445 megawatts were under construction; and license applications for an additional 13,395 megawatts were pending. Many additional sites have been identified and are being studied for possible development.

Characteristics

The basic elements of a pumped storage project are a pumping-generating unit and upper and lower storage pools. The project generates electric power by releasing water from the upper to the lower pool. During the off-peak hours when project capacity is not required by the system, water is pumped to the upper pool using energy generated by other sources, usually by large modern steam-electric units. A pumped storage project consumes more energy than it generates. Its economic advantage comes from converting low-value low-cost off-peak energy to high-value on-peak capacity and energy and from the highly flexible peaking power it makes available.

Two types of pumped storage projects have been developed. The first type is one in which pumped storage features are included in the design of a conventional hydroelectric installation. Here some of the streamflow is pumped back into the normal storage reservoir to provide greater capacity during peak-load periods. The second type is designed exclusively as a pumped storage project, where power is generated by recirculating water between lower and the upper reservoirs. Particular projects vary widely in design and modes of operation. "Combined" projects in which water is pumped from a main stream reservoir to an upper pool and discharged into the stream channel below the main stream reservoir are popular. An advantage of this design is that pumping head is less than the generating head.

The combined pumped storage installation has several other significant advantages. A major increase in dependable capacity of a hydroelectric plant can be achieved by including pumped storage features. In many cases sites having small stream flows and reservoir capacities can be economically developed as combined pumped storage installations, thus increasing significantly the number of sites which can be used for construction of hydroelectric peaking capacity. The upper reservoir of a combined project normally has a relatively large storage capacity and this is capable of many more hours of generation than is feasible in pure pumped storage projects.

Pure pumped storage projects on the other hand offer some advantages unmatched by the combined projects. For example, large streams are not a prerequisite for pure pumped storage because the same water is recirculated between reservoirs. This feature opens up a wider selection of sites for possible development some of which offer higher heads than those encountered in combination projects.

Pumped storage projects generally serve a dual purpose of providing system reserve and of storing excess system thermal energy during off-peak hours and returning it to the system during peak hours. Storage time is normally a function of the project's assigned position in the system load curve and its planned reserve contribution. The storage time

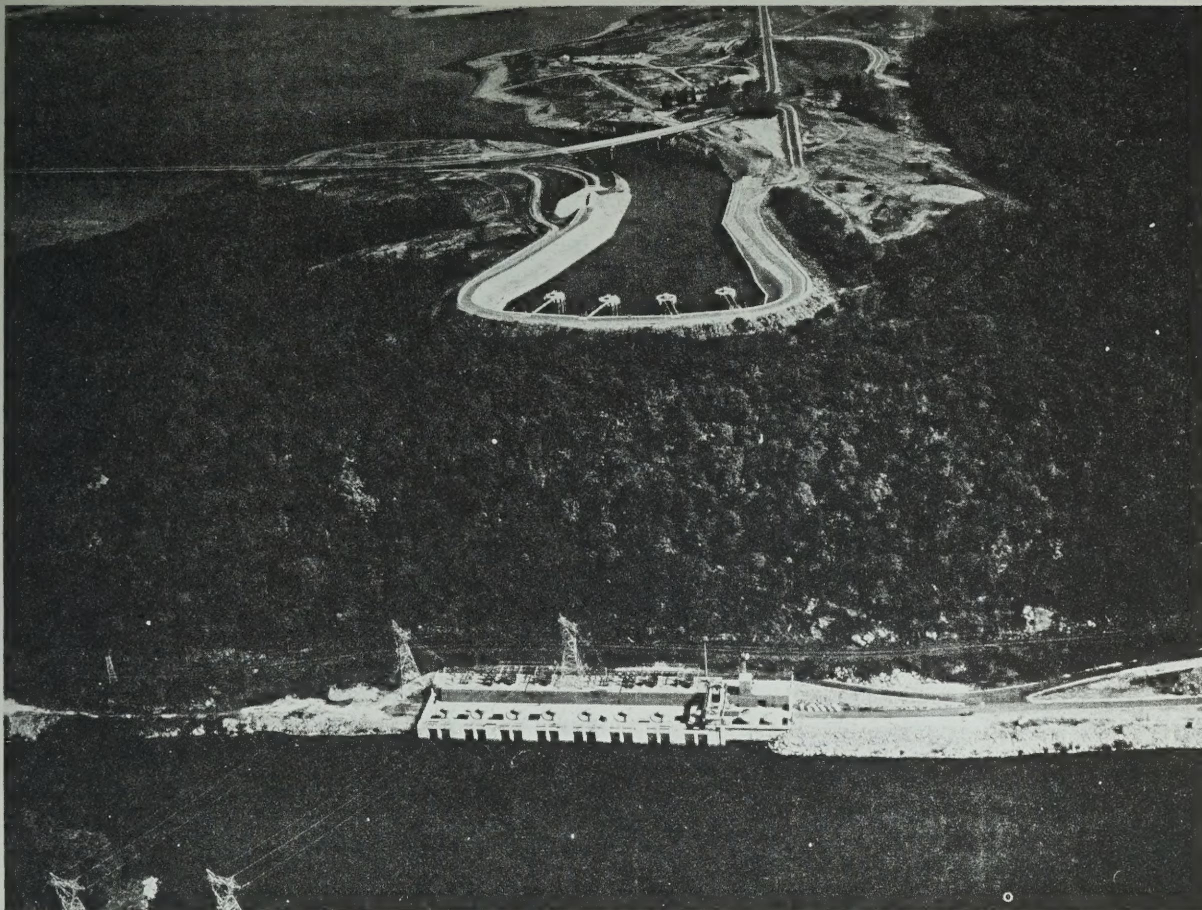


FIGURE 27.—Philadelphia Electric Company's Muddy Run Pumped Storage Project consisting of eight 110,000 kw units.

planned for will also directly affect the cost of the project, however, greater storage capacity increases the flexibility of operating a pumped storage project. For some systems it may be necessary to provide sufficient storage to provide full load operation of up to 16 hours.

When operated to serve short-time peak loads, this type of project will produce relatively few kilowatt-hours. When used to provide spinning reserve, it may operate at about one-half load or less for 10 to 12 or more hours per day, five days per week.

Existing or planned reservoirs in suitable terrain usually present attractive possibilities for pure pumped storage developments. The use of such reservoirs for lower pools reduces overall construction costs and improves economic feasibility of such developments.

At the present time nearly all pumped storage developments constructed or planned in this country are designed to use reversible units which are characteristically of high capacity (from 100,000 kilowatts up to planned capacities of 382,500 kilowatts). Heads are generally high ranging from 600 feet to 1,200 feet, though units with heads of about 300 feet are in operation in the Thermolito plant in California, and are proposed for the Ludington plant on Lake Michigan. Grand River Dam Authority's Salina Plant in Oklahoma has a 250 foot head. A 51,000 kilowatt plant with a rated head of 129 feet is currently in service at the Mormon Flat Plant in Arizona and a 96,000 kilowatt unit with a rated head of 246.5 feet is scheduled for operation in 1972 at the Horse Mesa Plant also in Arizona. Developments utilizing separate pumps and turbines are more common in some other countries. When the reversible units are rotated in one direction they function in the usual manner as turbines and generators. In the reverse direction they operate as pumps and motors. Owing to the losses in pumping and generating equipment, the energy required for pumping will exceed the amount of generation by from 35 to 50 percent. Making allowance for the expected generation of part of the output of the pumped storage project at part-load with less than optimum efficiency, it may be assumed for design purposes that approxi-

mately three kilowatt-hours of pumping energy are required for each two kilowatt-hours generated.

For a given pumped storage site, the higher the available head the more economical will be development and operating costs. Higher heads make it possible to generate the same amount of power using less water and smaller turbine-generator units. Operating costs per unit of installed capacity tend to decrease with increases in operating head and increases in unit sizes. Some existing projects have heads ranging up to 1,200 feet, but projects having substantially higher heads are being planned. Currently about 1,700 feet appears to be the practical limit for pumped storage projects. Operating economics also can be achieved by use of automatic or remote supervisory control.

A pumped storage hydroelectric plant produces electric power in the same manner as does a conventional hydroelectric plant. Both are valuable for peaking service. Certain limitations, however, affect the usefulness of a pumped storage plant. To offer an advantage to a utility system, the pumped storage plant must have available an ample supply of low-cost off-peak energy during its pumping cycle. In addition, the installation must have sufficient storage capacity in the upper reservoir to ensure the needed hours of operation to supply the selected portion of the load for which it was designed.

Capital and Operating Costs

Pumped storage schemes have to compete on an economic footing with all other forms of generation. The economic advantages of pumped storage include long life; low capital cost, ranging from \$100 to \$150 per kilowatt installed, and low maintenance costs, with possibility of remote controlled operation. Their quick-starting features, which are described above, permit using pumped storage as a source of a system's ready reserve. In addition, the relatively high ratio of machine inertia to power in hydroelectric units tends to promote system stability when pumped storage plants are operating. Advantages of some favorable sites for pumped storage may be offset by the expense of high capacity transmission lines required not only to transfer plant output to the center of demand but also to deliver pumping energy to the project. The need for transmission lines is an important consideration in pumped storage site selections.

Table III–2 lists the capital cost of a few selected pumped storage hydroelectric plants completed in recent years.

Advantages and Disadvantages

A pumped storage plant, even with a very high head, can have the same favorable operating characteristics as a conventional hydroelectric plant—rapid startup and loading, long life, low operating and maintenance costs, and low outage rates. By pumping in the offpeak hours, the plant factor of the thermal units is improved, thus reducing severe cycling of these units and improving their efficiency and durability.

Pumped storage plants can play an important role in assuring system reliability, a factor of paramount importance. When designed for this purpose, a high-head pumped storage unit may operate as a synchronous condenser, with the spherical valve closed, and still be fully loaded as a generator in about one minute. Plants in the lower head ranges may be operated as synchronous condensers without the use of cutoff valves and have a much faster response. In addition, a pumped storage unit can be brought from partial load up to its full load in a matter of seconds. This provides a desirable source of spinning reserve capacity to protect a system where forced outages have caused the load to exceed the generation. In the event of an emergency on the system during the pumping cycle the system load may be reduced quickly by dropping the pumping load to provide an effective form of quick load reduction. Pumped storage plants can also provide a source of startup power for steam-electric units.

Pumped storage capacity can be used to provide spinning reserve by operating the installation at partial load. When operated in this manner the pumped storage plant in many cases can achieve overall system savings by reducing the portion of the required spinning reserves assigned to operating units and hot-standby in steam-electric plants.

While pumped storage capacity is expected to increase materially in the future, there are a number of factors which will limit the total capacity which might be developed.

Pumped storage peaking projects are usually economical only when relatively high-head high-capacity projects are developed. They are, therefore, best adapted to those areas where the terrain is favorable and where they can be used in large interconnected systems.

Since energy for pumping must be transmitted to the pumped storage installation and the peaking energy must be transmitted to load centers, the distance of a proposed site from the source of pumping energy and load centers may place a limit on

TABLE III–2

Capital Cost of Typical Pumped Storage Hydro Projects

Owner	Name of plant	Capacity (MW)	Head (Ft.)	In-service date	Cost of plant ($000): Land	Structures	Reservoirs dams, etc.	Equipment	Roads and trails	Total	Cost/kW	State
Jersey Central Power & Light Co. and Public Service Electric & Gas Co.	Yards Creek	338.6	656	1965	817	3,227	13,530	11,014	419	29,007	86	New Jersey
Philadelphia Electric Co	Muddy Run	880.0	353	1967, 1968	894	12,047	33,171	26,348	988	73,448	84	Pennsylvania
Union Electric Co	Taum Sauk	408.0	790	1963	152	4,722	23,733	17,203	37	45,847	112	Missouri
Public Service Co. of Colorado	Cabin Creek	300.0	1,190	1966	......	6,563	16,155	8,634	393	31,745	106	Colorado
Grand River Dam Authority	Salina	260.0	245	1968, 1971	176	4,933	10,549	12,257	646	28,561	109	Oklahoma

the economic advantage of pumped storage compared to alternate forms of peaking capacity.

There is ordinarily little need for development of pumped storage peaking capacity in systems which derive a large portion of their power supply from conventional hydroelectric sources, since peaking capacity can usually be obtained at low cost by planning adequate initial capacity or utilizing opportunities to add capacity for peaking requirements.

There may be limitations on the availability of adequate supplies of low-cost pumping energy since there are usually relatively few hours each week night when the more efficient base-load units are available to provide pumping energy.

Hydroelectric installations will be expanded at many existing plants and new installations will be planned with larger peaking capacities. Where physical conditions are favorable for economic development, pumped storage will be utilized to an increasing degree in serving peak loads.

Evaluation and Use

Although it is technically possible to utilize modern high-efficiency thermal or nuclear plants at intermediate capacity factors, minimum energy costs are obtained with high capacity-factor operation. Thus, there is a need for complementary additional low capacity-factor generation. In some cases this can be provided by reducing the capacity factor on existing thermal plants. To the extent that such an existing plant is of relatively lower efficiency, this reduction may result in a saving in overall fuel costs. However, in many cases, there is a limit to the extent to which the need for low capacity-factor generation can be met by this means. Furthermore, the cost of operating such a plant at low loads, particularly where this involves a significant amount of standby service, can be high.

Essentially a pumped storage installation draws upon power and energy from a base-load plant during off-peak hours and returns it to the system during peak-load hours. The capacity factor at which the installation can operate during the generating cycle is determined by the shape of the system load curve, the proportion of the system load being met by pumped storage, and the capacity of the upper and lower storage reservoirs. Normally the average annual capacity factor of a pumped storage plant will be in the range of five percent to 20 percent.

The effective cost of energy from a pumped storage plant can generally be determined only by a study of total system production costs, with and without the proposed plant, as consequential changes in load factor of the associated plant are involved in the determination. However, as efficiencies and energy costs of thermal and nuclear plants level out, the effective cost of energy for pumping will be determined principally by the incremental cost of generation of the base-load plants in the system. With nuclear plants it can be low.

The effective use of pumped storage in the United States has largely resulted from development of the reversible pump-turbine, in which a single runner serves in both pumping and generation. Heads up to 1,700 feet are currently practical for such units. While use of relatively large units with capacity of over 300 mw, and increasing simplicity of design of control structures, have assisted in the economic application of pumped storage, the unit cost of such a project is determined primarily by topographic considerations. It is desirable that the head be as high as possible, com-

mensurate with the range of reversible units, to minimize turbine-generator costs and reservoir storage capacity.

Where the above requirements are fulfilled, pumped-storage generation can be economically attractive under present conditions; it is likely to become even more so in the future as the proportion of nuclear capacity in service increases. The flexibility of operation of a pumped-storage plant in meeting sudden load changes and its ability to provide high-inertia spinning reserve at low operating cost are major additional benefits that can weigh heavily in favor of this type of installation.

It is anticipated that pumped storage will be the major component of new hydro construction in the United States and that the extent of its future development will be limited only by the availability of suitable sites and a dependable supply of economical pumping energy.

Trends and Developments (1968-1990)

Equipment Design

(1) Size of Unit:

Unit sizes are expected to increase, but the practical limit on physical unit sizes today is the tip diameter of the runner as affected by shipping clearances. Runners of 215 and 221 inch diameter have been shipped in one piece; however, bids recently taken on a 360 inch diameter runner indicate that it will have to be split for shipment.

These limitations, of course, can be largely overcome if the owner is willing to bear the cost of field welding, machining and heat treatment of welds up to six inches thick on large units. Added costs however might be detrimental to the competitive position of pumped storage.

(2) Range of heads under which it is feasible to utilize combined pumping and generating units:

Single stage—Maximum about 1,700 feet

Multi-stage—Unlimited

(3) Starting problems as unit size gets larger—Some auxiliary method of starting reversible units is necessary for pumping operation. Since the direction of rotation for pumping is opposite to that for generating, reversible units cannot be self-started hydraulically.

All pump/turbines are installed below the pump suction water level and are, therefore, fully primed just before a pump startup. Adjustable-blade pump/turbines can be accelerated from standstill to synchronous speed in a reasonable length of time with the impeller blades in the closed position, but Francis-type pump/turbine impellers are usually dewatered for rapid acceleration before going into the pumping mode.

A full voltage, across-the-line induction motor start is the simplest and most economical method for unit capacities up to about 30 mw or more in large systems. Acceleration from standstill to synchronous speed can be accomplished in about 30 seconds.

For unit capacities up to about 100 mw in large systems, the most economical method of reducing the system disturbance due to full-voltage start is to use a reduced-voltage (usually 50%) across-the-line start. Acceleration time is about two minutes.

For unit capacities above about 100 mw, a separate pony motor is being used to accelerate the large machine to synchronous speed. Such a motor is small (five percent to ten percent nominal horsepower rating) compared with the main generator/motor; acceleration time will depend upon the moment of inertia of the rotating parts of the main units, but could be five to 10 minutes.

When full or reduced-voltage starting is undesirable or not feasible and it is desired to avoid the extra expense of a pony motor and associated equipment, synchronous starting may be arranged.

Synchronous starting has the advantage that the disturbance to the system can be zero. This method requires that a turbine (or another pump/turbine) be connected electrically at standstill to the unit being started. These two machines must be isolated electrically from the system during the accelerating period and the driving unit must have the torque-producing capability to accelerate the driven unit to synchronous speed. The accelerating time is usually in the range of two to five minutes and will depend upon the relative sizes of the two units, as well as upon dewatering (or not).

The generator/motor in going into pumping mode is usually synchronized while the pump/turbine is dewatered. Therefore, it is necessary to prime the impeller again before pumping can begin. This involves releasing the compressed air and allowing the water to refill the impeller while it is rotating at synchronous speed.

Plant Design

(1) Multi-stage underground pumped storage—Where acceptable rock structure exists within the depth of a proposed project, multi-stage underground pump storage possibilities will no doubt be investigated early in this period. The economic

feasibility of such a project has yet to be proven in this country but reports from Europe are promising.

(2) Aesthetics—Generally a low silhouette can be obtained in plant design; color selection in construction materials seems important to many people. In practically all cases, recreational facilities will be an important part of pumped storage installations, even though severe pool fluctuations may limit recreation to bank and vicinity areas of many projects. Extensions of the plantings areas to include the powerhouse and transmission line structures can be most helpful. In extreme cases, aesthetic considerations may lead to underground installations. These may be more costly or more economic depending upon the particular installations.

Efficiencies

Presently, pump-turbine efficiencies run from 90 percent to 92 percent. Some sacrifices in efficiency must be made in arriving at an optimum constant speed for pumping and generating. This compromise probably results in a loss of between two percent and four percent in overall efficiency, leaving little room for improvement in machine design.

Cycle efficiency is related to manner of plant operation as well as to pump-turbine efficiency, generator-motor efficiency and conduit head losses. Probably the highest cycle efficiency available in a pumped storage installation with short conduits will be about 80 percent, but this will require all operations at the best point. The cycle efficiency of some existing pumped storage installations runs as low as 50 percent, however, most proposed plants are designed for efficiencies in the range of 66 percent to 72 percent.

Improvements and Innovations

(1) Development of high head multi-stage units.

(2) Consideration of low head four-way reversible units capable of pumping and generating in either or both directions for tidal applications.

(3) Field fabrication and assembly of large units where the individual components are beyond normal shipping capacities.

(4) Designs toward increasing specific speeds in order to reduce size and overall cost of large units.

(5) Divided draft tube applications with the use of two lower reservoirs.

(6) Development of the Isogyre Unit—The Isogyre pump-turbine comprises basically an independent turbine runner and an independent pump impeller on the same shaft in the center of a spiral casing common to both runner and impeller. Around the turbine runner is arranged a movable guide-vane distributor and stay ring whereas around the pump impeller is arranged a conventional diffuser with stationary vanes. Moreover the machine is provided with two sleeve valves, one on the turbine and between the runner and the spiral casing and the other on the pump and between the impeller and the spiral casing. These valves operate independently of each other and serve to isolate and unwater the impeller when the machine operates as a turbine or inversely to isolate the runner when the machine acts as a pump.

Outstanding features of the Isogyre unit are:

a. Direction of rotation of the machine remains the same whether it operates as a pump or turbine.
b. No special provisions are necessary to start the unit as a pump since the machine is run up to speed as a turbine, synchronized, and then changed over to pump operation.
c. Separate turbine runner and pump impeller permit optimum design of each.

(7) Development of water cooled motor-generators.

Operating Requirements

Other than the normal requirement of being available to meet the daily peaks, the pumped-storage plant seems to be, if so designed, a favorable choice for regulation of system frequency. Units with the ability to operate over a wide range of gate openings in both the pumping and generating modes would make these plants ideal for fast and accurate tie-line regulation. The fast governor or gate response time to load changes are also best suited to using pumped-storage units for a crank start of a dead steam system.

Suggested Areas for Research and Development

The following is a listing of topics and subtopics which are recommended for research in the field of pumped storage.

1. *Reservoirs and Conduits*

(1) Effects of rapid drawdown, ice action, temperature gradients and water quality control, aeration requirements and methods.

(2) Spillway requirements, level control in upper reservoirs, fish protection requirements, low flow augmentation requirements and methods.

(3) Seepage control, methods of sealing reservoirs and their effectiveness and durability.

(4) Vortex formation and suppression, loading and vibration of trash racks, trash accumulation.

(5) Flow conditions under high velocity at bends and expansions, manifolded supply or discharge conduits, model and prototype.

(6) Rock mechanics, its effect on tunnel design and linear design, underground powerhouses, the use of mechanical moles and the possibility of unlined tunnels.

2. *Machine Design*

(1) Hydraulic transients, wicket gate timing, methods of calculation, computer programs, prototype measurements and equipment.

(2) Machine-caused pressure pulsations and vibrations, model and prototype measurement, transient loadings on bearings and also on the electrical system, methods of damping.

(3) Development of reversible pump turbine types for higher heads and greater capacity, possibly with integral valving arrangements, "ring" gates, divided draft tubes, governor control, prototype performance tests, field fabrication.

3. *Operation and Maintenance*

(1) Methods of starting, modes of operation, timing and control in various modes, (e.g. from cold start, from spin mode, etc.).

(2) Plant availability (outage times) reliability, derating formulas, overall cycle efficiency.

(3) Operation and maintenance experiences, value of fast response or loading.

4. *Plants*

(1) Underground pumped storage plants.

5. *Environmental Improvement*

(1) New Facilities.

(2) Existing facilities.

CHAPTER IV

COMBUSTION GAS TURBINES AND DIESEL ENGINES

Summary

Combustion gas turbines and diesel engines will continue to be used in increasing quantities as loads continue to grow. Such devices are very useful in that they can be installed quickly at relatively low capital cost and at almost any reasonable location convenient to the power system.

The use of combustion gas turbines has been growing more rapidly than the use of diesel engines. With increases in sizes of diesel engines it could be expected that their use will continue to grow.

Combustion Gas Turbines

The combustion gas turbine generating unit is in general use by the utility industry as a major source of peaking and emergency power. In at least one utility service area of Alaska, however, gas turbines provide over two-thirds of the entire power supply. Plants with single prime movers are currently available in ratings up to 60,000 kw and with multiple prime movers up to 240,000 kw. Plans are underway to increase the size of single prime mover units as experience is obtained. The single shaft industrial unit has been commercially available since the early 1940's with sizes now ranging up to 60,000 kw.

Since 1962 the aircraft jet engine has been offered as an electrical power generation unit through a dual shaft design which mates it with an expansion turbine. Capacities of 20,000 kw are currently available in single engine units of this design. Multiple jet engine configurations are also available in many capacities up to a maximum of eight engines powering a single hydrogen-cooled generator producing 160,000 kw.

There are advantages claimed for both the industrial and jet engine type of unit. The industrial unit is patterned after central station steam equipment and manufacturers claim long life, relatively low maintenance and high reliability. Manufacturers of jet engine plants claim rapid start-up, greater efficiency, and minimum down time through engine substitution. Maintenance costs are reported by some companies to exceed those for industrial gas turbines.

Several factors have contributed to the rapid growth of gas turbine generating capacity during the 1960's: an accelerated rate of growth of power usage, long lead times for construction of conventional plants, unanticipated delays in the construction of new plants, installation of vastly larger units making networks more vulnerable to the failure of individual units, lower capital costs than for conventional plants including those of moderate efficiency, and replacement of very old inefficient units.

Combustion turbine plants are pre-engineered and largely prefabricated. They can be erected and made operable on previously prepared foundations in approximately four months. Cost variations occur mainly because of variations in the need for transformers, variation in on-site transmission requirements, variations in soil conditions, variations in fuel facilities, and variations in acoustical requirements. Reported costs on maximum peak output base have ranged from \$75 to \$100/kw for the complete plant which compares with \$100 to \$150/kw for moderate efficiency steam units.

Thermal efficiencies of gas turbines are generally low, with heat rates averaging about 14,000 btu per kwhr. Because gas turbines are presently limited to burning higher grade fuels, namely natural gas or the higher fractions of petroleum fuel, energy costs are generally high, currently in the range of 5 to 20 mills per kwhr. Accordingly, gas turbines are generally limited to low capacity factors and until such time as substantial improvements are made in plant heat rate or operating cost, they will continue to occupy this status.

As a result of the low capacity factor, the capital cost component of energy is also extremely high. Thus, a unit operating with a five percent capacity factor could very well have a total power production cost of 12 to 15 mills per kwhr. The selection

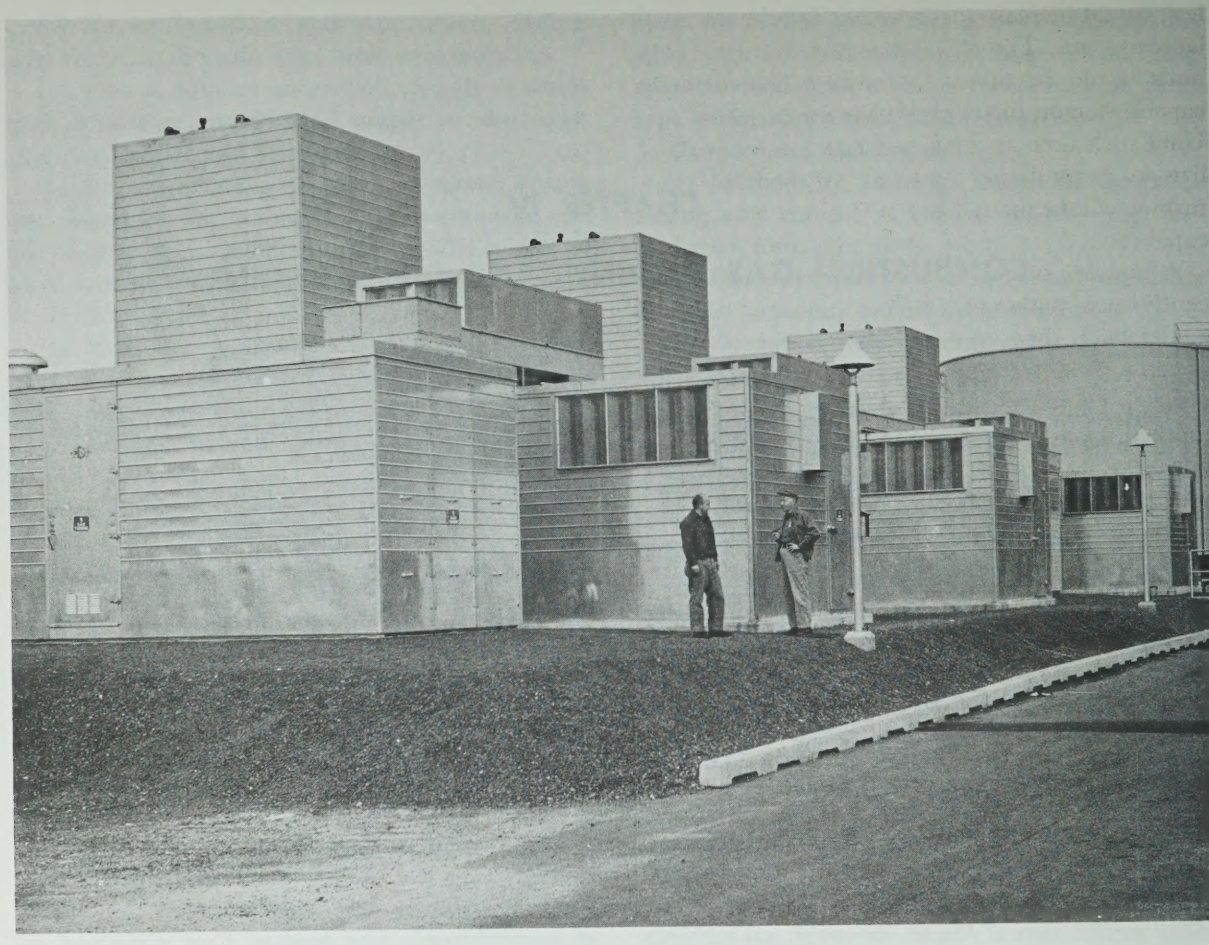


FIGURE 28.—Philadelphia Electric Company's Southwark Station. A three unit 60,000 kilowatt gas turbine installation.

of gas turbine apparatus therefore is not based solely on economics of operation, but on total costs to the utility to supply the peaking component of the load.

It is in the application of the unique characteristics of the gas turbines that these units have a place in the power generating mix. Gas turbines generally are available with starting, synchronizing and full load durations of 3 to 15 minutes with the jet engines having the shorter starting cycle time. Those units which can be started and loaded within three to five minutes qualify as ready reserve capability in most system operations. The effect of having a portion of reserve requirements of a system in such quick starting gas turbine apparatus is to load more efficiently other generating apparatus in service with the resulting savings attributed to the gas turbine installation cost.

The peaking capability of these types of units is, of course, self-explanatory and their independence of other ancillary systems allows their selection for emergency or "black plant" start-up application.

Gas turbines do not require cooling water, nor large areas for on site fuel storage. Hence, they may be located close to load centers and in bulk power substations. They enjoy advantages in site locations that other types of generating apparatus would not.

Sound attenuation has progressed substantially and their use of high quality fuels with less potential environmental pollution is making them acceptable neighbors in most areas.

Gas turbines have generally been limited by a number of considerations, including those associated with mass flow, expansion at the high temperature operating conditions and the requirements for air-cooled generators in remote or quick starting applications. As system sizes increase, the need for large size gas turbine units will demand resolution of these factors or combination of gas turbine units with other generating apparatus. The injection of water into the combustor discharge offers some opportunity in these directions, but the cost and availability of large volumes of water of the required purity presents a disadvantage.

Continued research and development to produce larger units, with heat rates of 10,000 btu/kwh, or

less, would increase the field of use, particularly in large systems. The effect of larger, more efficient, units would be to permit operation at a higher capacity factor, further reducing total energy costs. Until such time as total power production costs of five to six mills per kwhr are achieved, the gas turbine will be limited to a small fraction of system capability.

A number of gas turbine installations have recently been made because of the short delivery and construction time between date of order and date of commercial service. In some cases, where standardized components were available in factory-finished inventory, this interval has been less than one year, as compared to three to six years for other forms of generation. This is believed to be a temporary situation where short term impetus to gas turbine applications is not expected to prevail. The gas turbine will therefore have to compete on its own merits as part of the total generation mix.

In units employing simple cycles and air-cooled generating apparatus, a number of applications currently allow for remote starting and loading and almost unattended operation. Dependence on this type of unit for emergency service has presented some risk in that failure to start initially cannot be resolved remotely, but requires the transportation of qualified personnel to distant points. Gas turbine starting reliability has been fairly high but it does not approach that of the transformer and transmission line systems.

A few installations have combined gas turbines and steam cycles, and some engineering and manufacturing companies are actively engaged in promoting combined cycles. Although some designs are still in the development stage, combined cycle machines are being actively marketed. Heat rates of about 9000 btu/kwh and relatively low capital costs make them attractive.

Steam and water injection in a gas turbine cycle should offer considerably greater opportunity provided the restrictions on use of water and the problems associated with water purity are resolved.

The use of gas turbines utilizing the output of gas cooled nuclear reactors is receiving increasing attention, and this area offers the greatest potential for gas turbine applications in the 1990's.

The use of less expensive fuels have been proposed for gas turbines for more than 20 years with little result. The future prices of natural gas and high grade fuel oils will increase substantially to the detriment of the conventional gas turbine application.

Small combination installations where relatively low levels of heat can be used in a process will continue to be made, but combined cycles appear to offer no particular advantages over the direct use of electric energy in these future plants.

Diesel Plants

Diesel units of 40,000 kw are now available in single engine generator, factory assembled packages, and by 1990 units up to 100 megawatts could be available, assuming continued interest and research.

The addition of automatic control and starting equipment has given these units the advantages of remote, unattended operation, similar to that of the gas turbine.

Although the Diesel unit has a slightly higher capital cost than that of the gas turbine, it has a considerably better efficiency with present heat rates in the order of 10,000 btu per kwhr. The ability of Diesel generators to assume full load within one to three minutes from cold start is the most rapid of all the forms of prime mover available to the utility system today.

Diesel engine maintenance is one of the biggest problems to be overcome. Design and manufacturing techniques of American built apparatus will have to undergo considerable improvement to match utility requirements and to obtain the availability and production costs commensurate with alternative generation forms. The Diesel engine generating units expected to be available by 1990 will have the same type of application and limitation as the industrial or jet engine type of gas turbine. Improvements in heat rate are not expected to be significant, but greater utilization of less expensive fuels will enhance the use of the diesel-powered generator.

CHAPTER V

POSSIBLE NEW METHODS OF POWER PRODUCTION

Summary

A number of energy conversion devices have been extensively investigated in recent years in a search for lightweight, long-lived, and reliable power sources for space and special military applications. Some of these have received further consideration with the anticipation that they might prove sufficiently economic to compete with conventional generating equipment in the production of civilian power. The concepts that have received the most serious consideration are magnetohydrodynamics, fuel cells, thermionics, thermoelectrics, and electrogasdynamics.

In addition to the energy conversion devices that would convert chemical energy, kinetic energy, or heat to electricity, controlled thermonuclear fusion offers the possibility of direct conversion of the energy of nuclear fusion to electricity.

Nuclear fusion and all of the energy conversion techniques under consideration today were examined from the viewpoint of availability for general use by the utility industry by the year 2000.

It was concluded that of the energy conversion techniques being considered today, only magnetohydrodynamics and fuel cells appear to be sufficiently attractive and far enough advanced in the development cycle to be possible competitors in the production of power in this century. With the very recent renewed interest in solar energy conversion, however, there is some belief that it could become a significant energy source within this century. The two methods of conversion being considered are a sunlight-thermal energy-steam-power cycle and a sunlight-algae-methane-steam-power cycle.

The feasibility of nuclear fusion has not yet been demonstrated. It is unlikely that nuclear fusion will be a major contributor to power generation in this century unless the pace of development is substantially increased or technical progress of a "breakthrough" nature occurs.

Introduction

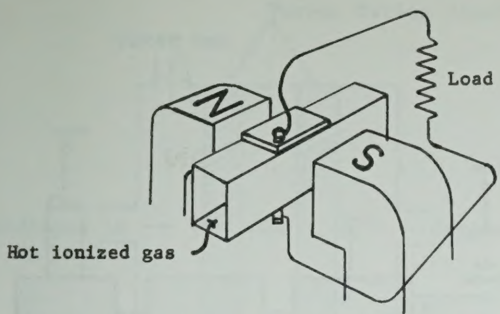
The generation of electric power requires two somewhat separable items. For example, an energy source such as water power or a coal-fired boiler and a turbine-generator. In a sense these items, an energy source and an energy converter, can be considered separately since most energy sources will power more than one type of converter. Since various energy sources such as reactors, fossil fuels, and water power are covered adequately in other sections of this survey, the emphasis here is on energy conversion. The single exception is the fusion reactor which is also discussed.

Basically, the generator part of a modern station operates on the same physical principle, electromagnetic induction in a moving wire, that was used in the first electric generator. However, modern stations involve massive equipment, temperatures about 1,000 degrees Fahrenheit, pressures as high as 3,500 pounds per square inch and rotational speeds up to 3,600 revolutions per minute. For many years engineers and scientists have studied the possibilities of generating electricity with less complex devices.

The basic principles which would permit technical achievement of this objective have been known for many decades, but the outlook for the economic utilization has not been considered promising. More recently the need for power plants for space and special military applications has resulted in the channeling of much research and development effort into these areas of electricity production. The general objective has been to produce a light, long-lived, and perhaps noiseless power plant which could operate with little or no maintenance. Considerable success has been achieved in this area by the use of new energy conversion methods and extension of these technologies to commercial central station power plants is often proposed. The purpose of this chap-

FIGURE 29

MAGNETOHYDRODYNAMIC (MHD) GENERATION



ter is to review the various concepts under development and to estimate their impact on commercial power generation in this century.

Magnetohydrodynamic (MHD) Generation

MHD, magnetohydrodynamic generation of power, is usually based on electromagnetic induction as are conventional generators.[1] In MHD, however, the moving conducting wire is replaced by a moving stream of gas made conductive by high temperature and subsequent ionization. (Figure 29). The ionization is often enhanced by the addition of a "seed" of easily ionized material such as cesium. The differences in the nature of solid conductors and ionized gaseous conductors cause unique mechanical, materials, and control problems in MHD power generation. The motion and electrical characteristics of solid conductors are simple and very well known, whereas, the motion and conduction of ionized gases (plasmas) are complex and still under study.

MHD power generation requires very high temperatures (up to 5,000°F) which leads to a high Carnot efficiency. Since the exhaust gases are still hot by conventional standards a combination plant utilizing a conventional steam cycle is usually proposed for a total thermal efficiency of 50 percent or more. The high temperature of MHD also tends to increase plant size since thermal losses are large in small-scale configurations. Most demonstration models built to date are quite inefficient due to thermal losses. The high temperature requirement produces materials problems and a large portion of MHD research has been on the development of satisfactory electrodes, insulators, and wall materials.

It is probable that the initial commercial applications of MHD will be simple designs for peaking use, avoiding the complications of steam cycle and the use of difficult-to-handle fuels such as coal. The Edison Electric Institute is now studying such a plant.

The poor electrical conductivity of the ionized gas has led to a search for means of providing very high magnetic fields and a large impetus was given to MHD by the development of the superconducting magnet. Most currently proposed MHD systems use superconducting magnets, however, the use of large size superconducting magnets in MHD devices has yet to be demonstrated. MHD generators are direct current devices and, as such, inverters are needed to produce alternating current. Future progress in DC power transmission could affect the desirability of this feature.

MHD power generation can be accomplished through either an open or closed cycle. As proposed for chemical or fossil fuel, the power plant is open cycle and, as proposed for nuclear fuel, it is closed. The nuclear closed MHD system requires considerably higher reactor temperatures than are achievable today and such a power plant appears to be many years away.

The chemical open cycle MHD power plant requires a high degree of fuel purity, and seed recovery is necessary if an easily ionized seed material such as cesium is used to enhance gas conductivity. In the case of a coal-fired MHD generator, it is necessary to process the coal into another form such as char before combustion. Most currently proposed MHD plants involving coal are of the hybrid variety, illustrated in Figure 30, which minimize air pollution and produce valuable chemical by-products. MHD generation of power from coal has not been demonstrated.

The future of MHD central station power is uncertain and difficult to assess. Although the basic concept of MHD power generation has been demonstrated, the extrapolation to even prototype central station power plants appears to pose a number of unique engineering problems. Among the many proposals made and small-scale programs conducted to date, none has generated sufficient financial interest from the Government or private industry to support the construction of a prototype plant. The nuclear, closed cycle MHD plant requires an extremely sophisticated reactor and appears to be far in the future. The open cycle,

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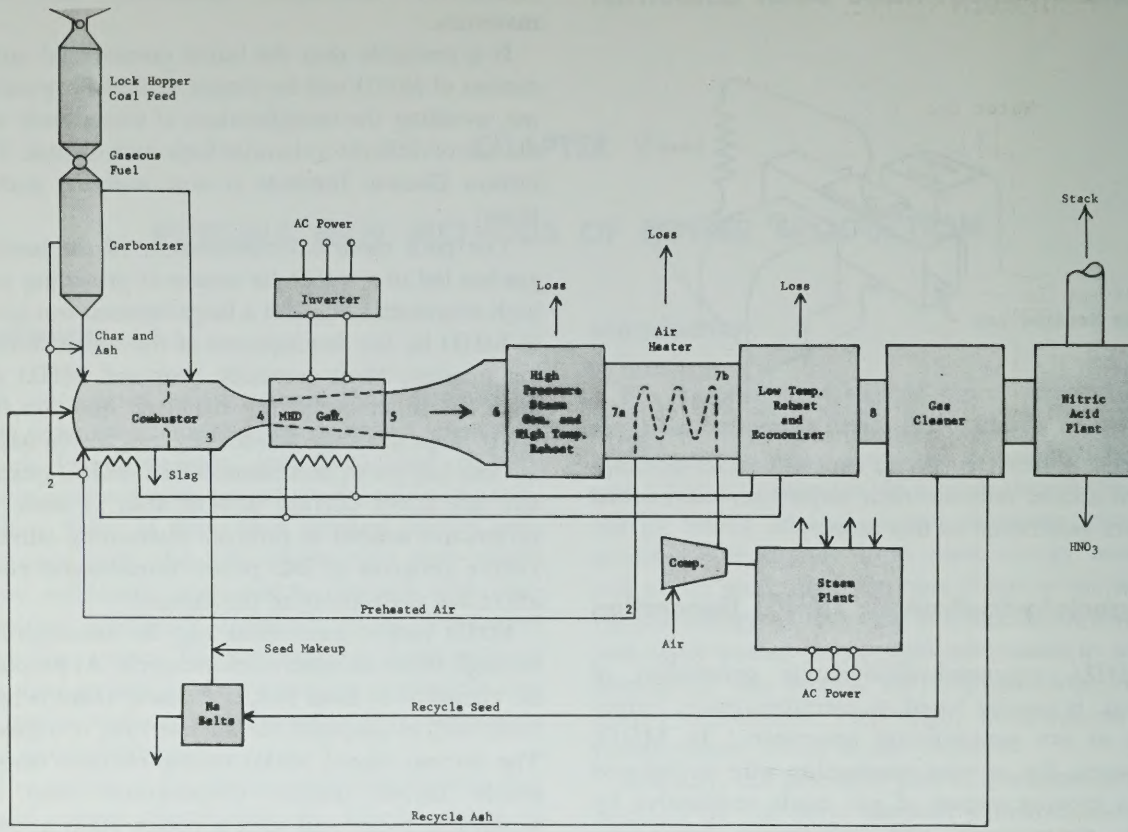
[1] Some MHD generators take advantage of the Hall effect which produces an axial electrical field within the duct.

FIGURE 30

SCHEMATIC DIAGRAM OF MHD-STEAM PLANT



Tsu -- MHD Power Generators in Central Stations

chemically fueled MHD plant will probably remain in the research and technology phase unless a significant change occurs in either plant design requirements or engineering approach.

A recent proposal to use MHD conversion for emergency or auxiliary power has not been fully evaluated. The backers claim advantages due to the extremely short startup time, even for very large units. All the unique engineering problems mentioned above still exist for these plants and the requirement for large emergency plants is open to some question.

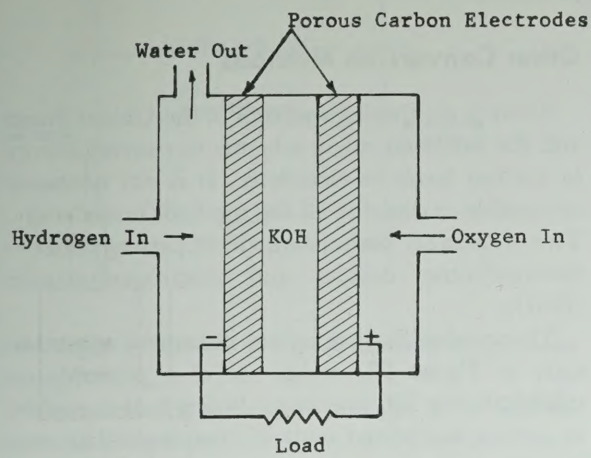
Fuel Cells

The principle of the fuel cell was discovered more than a century ago. It is an electro-chemical device in which chemical energy of oxidation of conventional fuels is converted directly into low voltage direct current without the use of a heat engine cycle. Fuel cells have the basic elements of a battery—positive and negative poles, and an electrolyte—but, unlike batteries, the energy to be converted is not stored in the cell. In any type of fuel cell, it is necessary to combine the fuel, such as hydrogen, with the oxidant, either pure oxygen or air. The driving force that keeps the fuel cell operating is the free energy of the chemical reaction. The chemistry of the simple hydrogen-oxygen cell, for instance, is basically as follows: at the oxygen electrode, hydroxyl ions are formed by removing electrons, thus leaving the electrode positive; at the hydrogen electrode, hydroxyl ions combine with hydrogen to form water, giving off electrons in the process. Consequently, the hydrogen electrode becomes negatively charged with respect to the oxygen electrode, and a current can be made to flow through an external circuit. The principle involved is indicated in Figure 31.

Many types of cells are being investigated, encompassing a wide range of temperatures and pressures and using rather complex electrolytic chemistry. Present attempts to use hydrocarbons directly have met with little success. Processing light hydrocarbons and feeding the by-product to the cell as a fuel has been suggested as a possible

FIGURE 31

HYDROGEN-OXYGEN FUEL CELL



solution to the problem. Both low and high-temperature solid and molten electrolyte fuel cells show promise. The solid or molten electrolyte, high-temperature cell operating at 2,000°F, appears capable of using any fuel directly, including coal.

There is a class of fuel cells in which the chemicals used to produce the electricity may be thermally regenerated and recycled through the cell. This type of cell could be operated in conjunction with a number of different heat sources including the nuclear reactor. The thermally regenerative fuel cell is limited to Carnot efficiency, but overall efficiencies of up to 40 percent are possible.

Fuel cells which produce electricity through oxidation of hydrogen or hydrocarbon fuels are not limited to Carnot efficiencies. Fuel cells operating on pure hydrogen and oxygen are currently being used in a few limited military and space applications. Hydrogen is an expensive fuel, and fuel cells are neither economically competitive with commercial power sources nor commercially available in large sizes at the present time.

Considerable interest has been shown in fuel cells for industrial and residential use. This interest results from the fuel cell's lack of moving parts, its freedom from the Carnot efficiency limitations, and the present economics which allow delivery of natural gas to a consumer at a lower cost than that of the equivalent unit in the form of electricity. General acceptance of the concept of delivering fuel to a customer and allowing him to use it for heating, cooling, electricity, or whatever he decides, would dramatically change the present electric power industry. Although present economics and engineering requirements would seem to indicate that the first use of fuel cells should be for industry using large amounts of low voltage, direct current power, the initial development of small residential applications, although more technically difficult to realize, might be more attractive to the consumer. Later, expansion could be made to industrial or commercial markets. The fuel cell is being considered for all these applications. The major problems involve raising the lifetime of present cells by an order of magnitude and reducing the capital cost per kilowatt by about the same factor. There are engineering difficulties in achieving such performance gains, but there is considerable enthusiasm among the fuel cell developers.

The fuel cell is a low voltage, direct-current device very similar to a battery in its electrical characteristics. To obtain reliable alternating current power from a fuel-cell installation would require large banks of cells, back-up equipment, and the use of inverters.

The future success of fuel cell projects is difficult to predict. The fuel cell has one advantage over other energy conversion schemes discussed herein. Funds and interest for development appear to exist within the gas industry. For the short term the engineering problems appear quite difficult, but certainly the possibility exists for fuel cells to have a large effect on the power industry before the year 2000, providing natural gas or other suitably processed fuel is available at competitive prices.

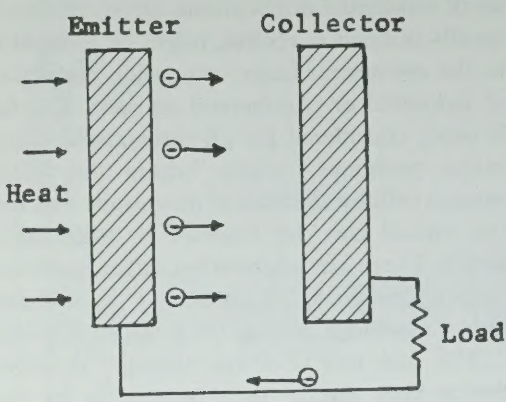
Thermionic Generation

Thermionic devices depend on the phenomenon known as the "Edison effect" (the emission of electrons by metals at high temperatures). The existence of this phenomenon was established in 1878 by Thomas Edison. The conventional heated filament vacuum tube is one application of thermionic emission.

As indicated schematically in Figure 32, a thermionic generator contains an electron emitter which is heated. Heating causes electrons to "boil off." These electrons have sufficient kinetic energy to move through an intervening space to a cooler electron collector. An electrical potential is created which enables a current to flow in an external load. The hot emitter also radiates heat to the collector, and this represents a loss in efficiency. For this reason, high current flow between emitter and collector (high power output) is desired to

FIGURE 32

THERMIONIC CONVERSION



hold radiation losses within a reasonable proportion of the energy input. However, the current flow tends to be limited by the "space charge" of electrons that build up around the emitter. This effect may be minimized by making the gap between cathode and anode very small, or by neutralizing the space charge with a material such as cesium which is ionized at the operating temperatures. The neutralizing approach is more efficient and practical than the "narrow gap" approach and consequently is almost exclusively utilized. Thermionic converters are characterized by low voltage and high direct current. Therefore, some sort of inverter transformer scheme would be necessary for commercial power use.

Thermionic generators combining satisfactory operating and economic characteristics for central station power plants have not been developed. Thermionic emission for power generation requires high temperatures. Three-thousand degrees Fahrenheit is considered a good minimum emitter temperature for such devices. The major problems involve emitter materials (refractory metals and alloys), close tolerance fabrication, and high temperature electrical insulators.

The desirability of such high emitter temperatures suggest the possibility of using a nuclear reactor fuel element as a heat source and the U.S. Atomic Energy Commission is developing such a reactor converter for use in space. The development problems are quite severe and the system efficiencies are quite low ($\sim$15 percent) compared to ordinary power plants. The nuclear reactor thermionic converter does not appear to have any potential at this time for civilian power use.

Chemically fueled thermionic conversion could be used as a topping cycle in a hybrid plant, but because of the low efficiency of thermionics compared to MHD, it is likely that MHD would be preferred.

Other Conversion Methods

There is continuing research in the United States and the world on many schemes to convert energy in various forms to electricity. It is not necessary or possible to describe all the methods under study. Two of them are perhaps worthy of passing notice—thermoelectric devices and electrogasdynamics (EGD).

Thermoelectric generation, illustrated schematically in Figure 33, makes use of a principle established over 100 years ago. When heat is applied to one of the joined ends of two dissimiliar conductors, the electron activity will be increased more in the material of one conductor than the other, so that a potential difference will be produced, the Seebeck effect. The thermocouple is a well-known example of a device of this nature. Clearly, if large currents are to be produced, the materials forming the junction must be good electrical conductors. This creates a problem because usually good electrical conductors are also good heat conductors, so that heat applied to the junction tends to be conducted away and wasted. Advances in solid-state physics in recent years have made possible the development of semiconductors which permit considerably improved efficiencies over those achieved theretofore with metallic type junctions. To obtain appreciable amounts of power,

FIGURE 33

THERMOELECTRIC GENERATION

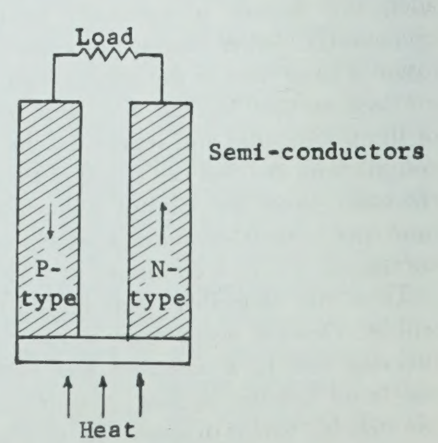
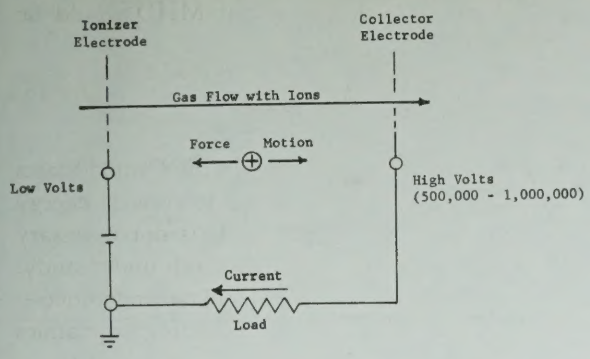


FIGURE 34

ILLUSTRATING THE EGD PRINCIPLE



the coupling together of a large number of junctions is required.

Thermoelectric generators appear to be limited to about ten percent efficiency, and therefore their use for central power stations is quite unlikely. They have found rather extensive use for small isolated and portable power sources.

Electrogasdynamic generators would use the kinetic energy of a stream of hot gas to physically transfer injected ions against an imposed electric field as shown in Figure 34. The principle is the same as most electrostatic generators, except that a gas is used as transfer agent rather than a moving wheel or belt. EGD poses severe insulation problems due to the high gas temperature combined with extremely high voltage. Most demonstrations have been at room temperature. To date, EGD has shown more problems than advantages, and the present outlook for development of a practical generator is poor.

Controlled Thermonuclear Fusion

Most energy sources—specifically, nuclear fission reactors, fossil fuels, and water power—are covered adequately in other sections of this survey. A major exception is energy from controlled thermonuclear fusion. This potential large-energy source will operate at a sufficiently high temperature (with much of the energy in a gaseous form) that the energy converter to be used may be something other than the common turbine generator. Indeed any of the new energy converters could be used with fusion energy.

The controlled thermonuclear reactor (CTR) will be a unique heat source in terms of unlimited fuel availability and high temperature, which offers the possibility of direct conversion by use of the plasma involved. Although the unsolved scientific and engineering problems are very complex, the possibilities of creating a vast new source of electrical power has made research on the CTR a national and worldwide effort.

Thermonuclear fusion consists basically of combining the atomic nuclei of very light elements—ie. hydrogen (in the form of deuterium or tritium) or helium-3—by collision at high velocities to form new and heavier elements. The amount of energy released in the process is a function of temperature. To obtain thermonuclear fusion and from it a net energy output, requires temperatures of at least 40 to 100 million degrees Fahrenheit. At about 100,000°, the gas molecules used in fusion dissociate into individual atoms and the orbital electrons separate from the nuclei. Such a random mixture of nuclei and unattached electrons is commonly called a plasma and can be considered as a fourth state of matter.

The basic processes involved in CTR exist in the sun and stars and have been demonstrated in fusion weapons. In the sun and stars the fusion process is stabilized by the gravitational field of the body; in weapons the fusion process is uncontrolled to the extent that the reaction is ended by the destruction of the device. The problem of the CTR is to find a suitable container for the hot plasma and to control the plasma losses (regardless of whether the power is continuous or pulsating) so that net power can be produced in quantities and at a cost useful to society. At the plasma densities currently being considered for controlled fusion, the rate of energy release cannot support a destructive reaction.

In a fusion reactor, the final reaction products (helium and neutrons) are not radioactive. As presently conceived the only radioactivity in the plant (other than fuel if tritium is used) would be that induced by neutron bombardment of the construction materials. Thus, there would be no radioactive fission product wastes.

Concepts for thermonuclear reactors are usually based on the use of magnetic fields to contain the hot plasma of charged particles. A schematic illustration of the components of a fusion reactor is shown in Figure 35. It appears possible that some of the energy released in fusion may be converted directly to electric energy. The results of recent research on fusion reactions have been encouraging. Neutrons from thermonuclear reactions have been observed in the laboratory since 1958, and small amounts of fusion energy can now be produced. (The energy input, however, is much greater than that released.)

Controlled fusion power will require a sufficient understanding of plasma physics to enable adequate control of plasma instabilities and to permit the prediction of reliable scaling laws. Considerable progress has recently been made in the control of instabilities. Once accomplished, a major engineering effort will be required. Current studies indicate that economic power plants will probably be very large. It took 20 years to engineer competitive bulk power stations using fission reactors. On this basis, fusion power is generally not expected to be a major contributor to central power station technology before 2000.

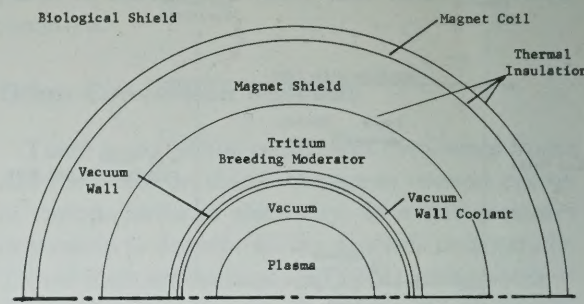
The practical development of fusion power would make available almost inexhaustible energy resources. The oceans contain virtually unlimited quantities of deuterium in heavy water which can be recovered economically. In view of the potential, fusion power must be considered a serious contender for a major role in power development in the future. Furthermore unpredictable scientific and technological advances could allow fusion produced power to become practical in a shorter time period than currently anticipated.

Conclusions

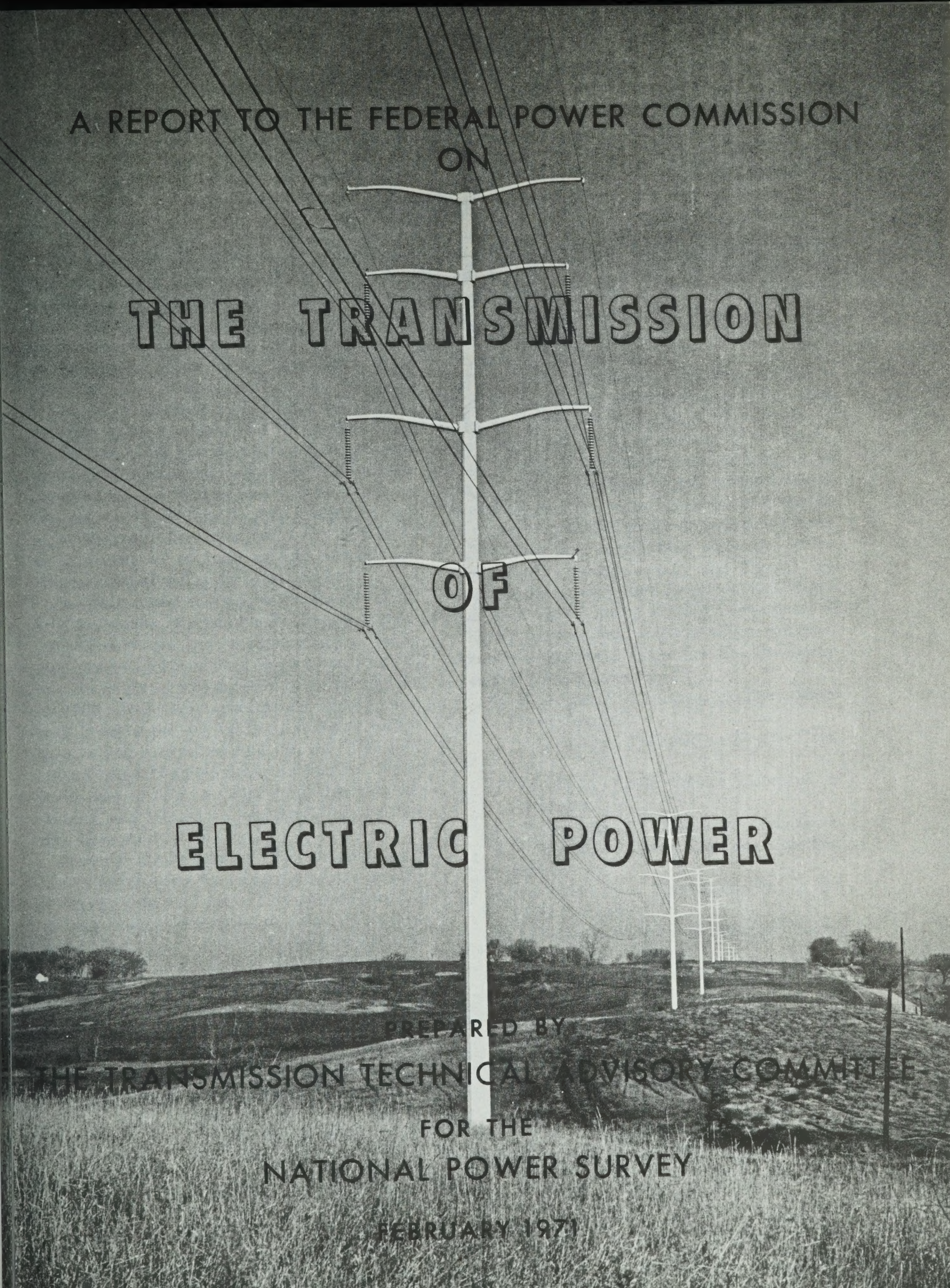
1. Of all the energy conversion techniques being considered today, MHD and fuel cells, appear to be the most attractive and far enough advanced in the development cycle to be the most likely contenders as new commercial power producers in this century.
2. MHD will probably not become competitive unless a sufficient change occurs in either plant design requirements or engineering approach such as a requirement for high thermal efficiency to reduce thermal pollution or the development of demand for direct current.

FIGURE 35

CONFIGURATION OF A CONCEPTUAL STEADY-STATE DEUTERIUM-TRITIUM FUSION SYSTEM



3. Fuel cell applications on a large scale would probably involve a restructuring of the power systems. This radical change, and especially the present high capital cost of fuel cells, does not make the immediate future particularly bright, but fuel cells could have a major effect before the year 2000.
4. The fusion reactor is a possible major contender as a new energy source. Such a reactor offers potentially significant advantages in fuel availability, operating temperature, environmental consideration, and other operational features. Since its feasibility is still to be demonstrated, nuclear fusion will probably not be a major contributor to power generation in this century unless the pace of the development is substantially increased or technical progress of a "breakthrough" nature occurs.
5. Research and development effort is underway on converting solar energy into electricity, and some believe that solar energy could become a significant energy source within this century.



A REPORT TO THE FEDERAL POWER COMMISSION
ON

THE TRANSMISSION OF ELECTRIC POWER

PREPARED BY
THE TRANSMISSION TECHNICAL ADVISORY COMMITTEE
FOR THE
NATIONAL POWER SURVEY

FEBRUARY 1971

PREFACE

The history of the electric power industry has been one of rapid growth throughout the years of its existence since 1882 when the first steam-electric generating plant was placed in service and a pioneer distribution system was established to supply lighting for offices in the downtown areas of New York City. Development through the years has produced extensive and complex transmission networks which now link virtually all parts of the United States and provide the means of achieving both reliability of service and the economies available through the effective use of large, low-unit-cost generators, sharing of reserve capacity, and more efficient utilization of all of the facilities in an interconnected area during both normal operating conditions and system emergencies.

As power system loads have increased and the need for transfer of larger blocks of power has developed, there has been a continuing increase in transmission system voltage levels from about 60 kilovolts at the turn of the century to 765 kilovolts in 1969. Even now, research and development work is well under way for the next higher voltage level, which is expected to be in the 1000–1500 kilovolt range. Need for such a transmission voltage is expected to occur at least within the next two decades, and some have forecasted that the time may be as short as ten years.

Concerns about esthetics and increasing problems of transmission line rights-of-way, particularly in heavily populated areas, have spurred industry efforts to produce new apparatus suitable for underground installation, and cables designed for operation at nominal voltages as high as 500 kilovolts are undergoing initial tests at this time.

Comparatively recent technological developments and the occurrence of particular problems, such as very long-distance transmission, high-voltage underground or underwater circuits, and special interconnection requirements, have created considerable interest in high-voltage, direct-current transmission systems. One major installation was placed in service in the U.S. in 1970, and significant research and development work is in progress on new devices for application to both dc power circuits and their control.

The Technical Advisory Committee on Transmission has explored the present state of the transmission art and has attempted to identify some of the trends likely to be experienced in the future. Attention has been directed to several areas where improvements in technology and methods may be needed to effectively meet the needs and challenges of tomorrow's electric power transmission systems.

The Committee membership represents the investor-owned, publicly-owned, and Federal segments of the industry, and the geographical distribution of the members enabled comparisons of different patterns and practices where variations occur from one region to another. The Committee members and affiliations are:

D. W. Angland, Chairman, Northern States Power Company

J. J. Dougherty, Philadelphia Electric Company

J. M. Dyer, Public Service Company of Oklahoma

W. F. Graham, U.S. Bureau of Reclamation

E. J. Harrington, Bonneville Power Administration

C. A. MacArthur, Pennsylvania Power and Light Company

C. H. Prior, Department of Water and Power, City of Los Angeles

C. L. Rudasill,* Virginia Electric and Power Company

G. S. Vassell, American Electric Power Service Corp.

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* Replaced J. A. Rawls, April 1, 1970.

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INTRODUCTION

Chapter 1 discusses the role of transmission in electric power systems and depicts the development trends which have led to the installation of the first 765-kV ac facilities in the U.S. during 1969 and the expected need for still higher voltages before the end of the 20-year period of the current power survey. The rapid growth in electric system loads, the economies of larger scale generators, the capabilities of the higher voltage transmission lines, and the reliability aspects of strong interconnections have promoted the development of connections which link the nation's power systems together in a network that now covers most of the United States, although some are yet very weak. The interconnections which exist today have already created an interdependence among systems that necessitates far greater coordination of planning and operation than ever before, and similar trends are expected to continue. The increasing competition for land use and growing interests in esthetics and environmental considerations, together with the continued trend toward larger concentrations of generating capacity, are expected to multiply the needs for underground transmission and higher voltage overhead systems. These potential needs emphasize the necessity of technological improvements and the demand for adequate technical talent to implement the required research and development programs to assure the availability of methods and equipment to meet the needs of tomorrow.

Chapter 2 discusses ac overhead transmission lines, the expected future needs for transmission voltages in the 1000–1500 kV range, and some of the problems with insulation at such levels. Sample and average costs of transmission lines of different voltage levels and in different geographical areas are presented, and typical loading capabilities for several configurations are given. Corona and radio influence effects are discussed briefly, and attention is directed to several of the more recent efforts to improve the appearance of transmission line structures.

Chapter 3 is devoted to ac transmission system terminal equipment, standard operating voltage and insulation levels, and insulation coordination practices. Switchgear, transformers, line compensation equipment, metering, relaying, and data recording equipment are treated in detail, and application trends are indicated. The impacts of a growing concern about physical and visual environmental problems on the location and design of substations are discussed together with suggestions of ways in which some of the anticipated problems of the future may be minimized.

Chapter 4 discusses steady-state transmission system overvoltage phenomena, origins of the abnormal voltages, and methods of dealing with the associated problems. Needs for development of convenient measuring techniques and analytical models are presented.

Chapter 5 considers the primary factors affecting system stability along with some effects of present development trends on stability. The presence and characteristics of automatic control schemes have a profound effect on stability. Studies which indicate the abilities of a system to develop restoring forces to overcome disturbances can aid in assessing system stability characteristics. The increasing use of extra-high-voltage (EHV) transmission networks, changing patterns of generation and transmission, increasing size of generating units, changes in boiler and turbine design, and improved control systems are some of the power system development trends that affect system stability.

Chapter 6 presents the state of the art in high-voltage dc transmission, descriptions and characteristics of the basic components of dc systems, and operational and control considerations related to present and projected dc applications. An indication of the land requirements for a dc terminal and economic comparisons with equivalent ac installations are discussed. A number of needs for future developments in control techniques, multi-terminal circuits, and advanced ac/dc converter technology are suggested.

Chapter 7 discusses general problems of EHV underground transmission and presents information about current research and development programs which supplements the data contained in the report on Underground Power Transmission prepared by the Federal Power Commission's Advisory Com-

mittee on Underground Transmission in 1966. The EHV cable development work being sponsored by the Electric Research Council is discussed.

Chapter 8 recognizes the importance of good communications in modern power system operation and control, and describes the types of equipment now used for the various communication and signalling functions. Anticipated needs for the future are suggested together with several new and more fully implemented functions of presently available types of communications which may be expected.

Chapter 9 reviews the general concept of a central control system and the evolution of today's complex computer control center from the relatively humble beginnings of a few years ago. The basic functions of a central control system are discussed: gathering, processing, and displaying information for system operator guidance; maintaining maximum system security; maintaining adequate voltages; adjusting generation in relation to system loads; minimizing overall cost of generating and transmitting energy to total system loads; and rapid restoration to normal after a system abnormality. The chapter also discusses future needs and a number of factors which are expected to affect future developments.

Chapter 10 discusses industry needs for high-voltage, high-power testing facilities in relation to present capabilities, and presents ideas about future installations to permit dynamic testing of new equipment under more realistic service conditions. The conclusion is that development of such facilities should be accelerated.

Chapter 11 directs attention to the complexity of analyzing the performance of modern power systems under both normal and disturbed conditions, and discusses methods currently used in design studies of system expansion. Needs for new and improved methods and techniques to cope with problems of the future are emphasized.

CHAPTER 1. THE ROLE OF TRANSMISSION IN ELECTRIC POWER SYSTEMS

1.1 Background

Three subsystems—generation, transmission, and distribution—compose an electric power system. It is the transmission system that links the generating sources of the power system with the many consumers connected to the distribution lines and interconnects adjacent power systems for operating economies and maximum reliability of service. Because of these roles in providing an essential commodity in modern life, and the fact that transmission systems are exposed to so many vagaries of nature and man, the importance of properly designed and operated transmission systems cannot be overemphasized.[1,2]

The transmission system in the main consists of (1) overhead aerial transmission lines and underground cables operated at 69,000 volts (69 kV) or higher, (2) terminal equipment, such as transformers, switchgear, lightning arresters, reactors, and capacitors, and (3) complex metering, communication, relaying, and control systems to operate and protect the transmission system. Substantial advanced engineering knowledge and effort are required to assemble these elements into the sophisticated transmission systems of today. Far greater engineering effort and research in many areas will be necessary to provide the future transmission systems needed to meet the increasing demands for electrical energy in the face of mounting technical, economic, and social problems.

1.2 The Trend to Higher Transmission Voltages

In 1950, the highest transmission voltage in use in the United States was 287 kV. In 1970, the highest transmission voltage in use is 765 kV, the first line having been placed in operation October 1, 1969. Table 1.1 shows the extent of ac extra-high-voltage (EHV) transmission lines in the United States at the beginning of 1970. EHV is defined as voltage levels above 230 kV and up to 800 kV.

The motivation for the trend to higher transmission voltages is, of course, the need to supply low cost, reliable electric service to a growing population having a vigorous growth in per-capita use of electrical energy. From 1950 to 1968, the annual electric energy usage in the United States increased from 281 billion kWhs to 1,202 billion kWhs, or 328%. It is reasonable to expect that this trend will continue into the future.

1.3 Voltage Standards

The American National Standards Institute, Inc., has established standard voltage levels for transmission systems. Present standard nominal voltages include 230 kV, 345 kV, 500 kV and 700 kV, although the latter is being revised to around 765 kV. Associated with each standard nominal voltage is a standard maximum voltage which is the highest voltage at which the system should operate and represents the design voltage of system components. The use of standard voltages by various power systems results in greater economy by minimizing the need for voltage transformation equipment between systems and by minimizing the variety of equipment designs required along with the associated research, development, and manufacturing effort. Standard voltage levels above 765 kV have not yet been established, and such standards will require much economic and technical study by the industry.

1.4 Role of Extra-High-Voltage Transmission

Extra-high-voltage (EHV) transmission in the development of an electric power system can assume one or more of the following three functions:

1. Long distance energy transfer from remote generating sources to load centers
2. Interconnections between areas previously isolated from each other, for purposes of

See footnote References, end of Chapter.

TABLE I–1

Circuit Miles of EHV Lines, January 1, 1970

Voltage levels	Approximate circuit miles
287	[1] 2,440
345	14,070
500	6,840
700 (765)	66

[1] Of this total, approximately 1,420 miles are being operated at 230 kV.

achieving economies in the utilization of available generation resources

3. Higher-voltage overlay on an existing, well-developed, lower-voltage system so as to allow such an overlay to take over the major tasks of bulk power transfer between generating plants and load centers within the system and to permit the continued integrated operation of the overall system in an economical and reliable manner.

A recent example of the first of the above functions of EHV transmission on the North American continent is the 735-kV transmission system of Hydro-Quebec, designed to make available the ample hydro resources in northern Canada to the population centers in the southeastern part of the country, some 380 miles away (Figure 1.1). An example of the second function is the construction

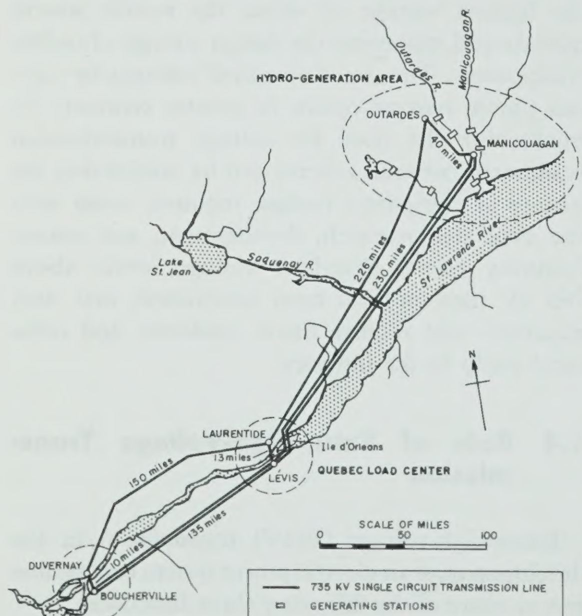

FIGURE 1.1.—Example of Long Distance Energy Transfer from Remote Generating Sources to Load Centers—735-kV Transmission System of Hydro-Quebec.

of the Pacific Northwest-Pacific Southwest Intertie, connecting at ±400 kV dc and 500 kV ac the hydro resources in the Pacific Northwest with the major load centers in California, over a distance of some 850 miles (Figure 1.2). An example of the third function of EHV transmission is the construction, now underway, of American Electric Power Company's 1,200-mile, 765-kV overlay on its existing, extensive 345-kV network (Figure 1.3). In each instance, the decision to proceed with a specific plan of EHV transmission development was predicated not only on an evaluation of short-term requirements, but also on a long-range appraisal of future needs. Thus, some of the EHV transmission systems originally intended to perform only one of the above functions may be called upon in the future, in the course of their development, to perform several functions and to change their primary role with time to meet changing conditions.

Whatever its specific role, the EHV transmission system constitutes in each instance a vital and indispensable link between the sources of bulk power generation and the major centers of electric energy consumption. Its strength is essential to the reliability of the overall bulk power supply and to the full utilization of the economies of scale inherent in large and more efficient generating units and plants. Its sound planning, design, construction, and operation constitute a prerequisite to the achievement of system economies without a sacrifice in the essential reliability objectives.

1.5 Factors Influencing EHV Transmission System Development

1.5.1 Introduction

The increasingly extensive use of EHV transmission in the United States is rooted in several basic technological, economic, and social factors, whose influence not only affected the past and present development of EHV transmission but also will continue to have a profound effect on future trends. The more important of these factors are discussed briefly below.

1.5.2 EHV Transmission Economics

As discussed in Chapter 2 of this report, the capability of a transmission circuit increases approximately as the square of its rated voltage. If, through research and technological improvements, a transmission circuit can be built for higher rated voltages at a cost that increases less than its transmission capability, then the higher voltage trans-

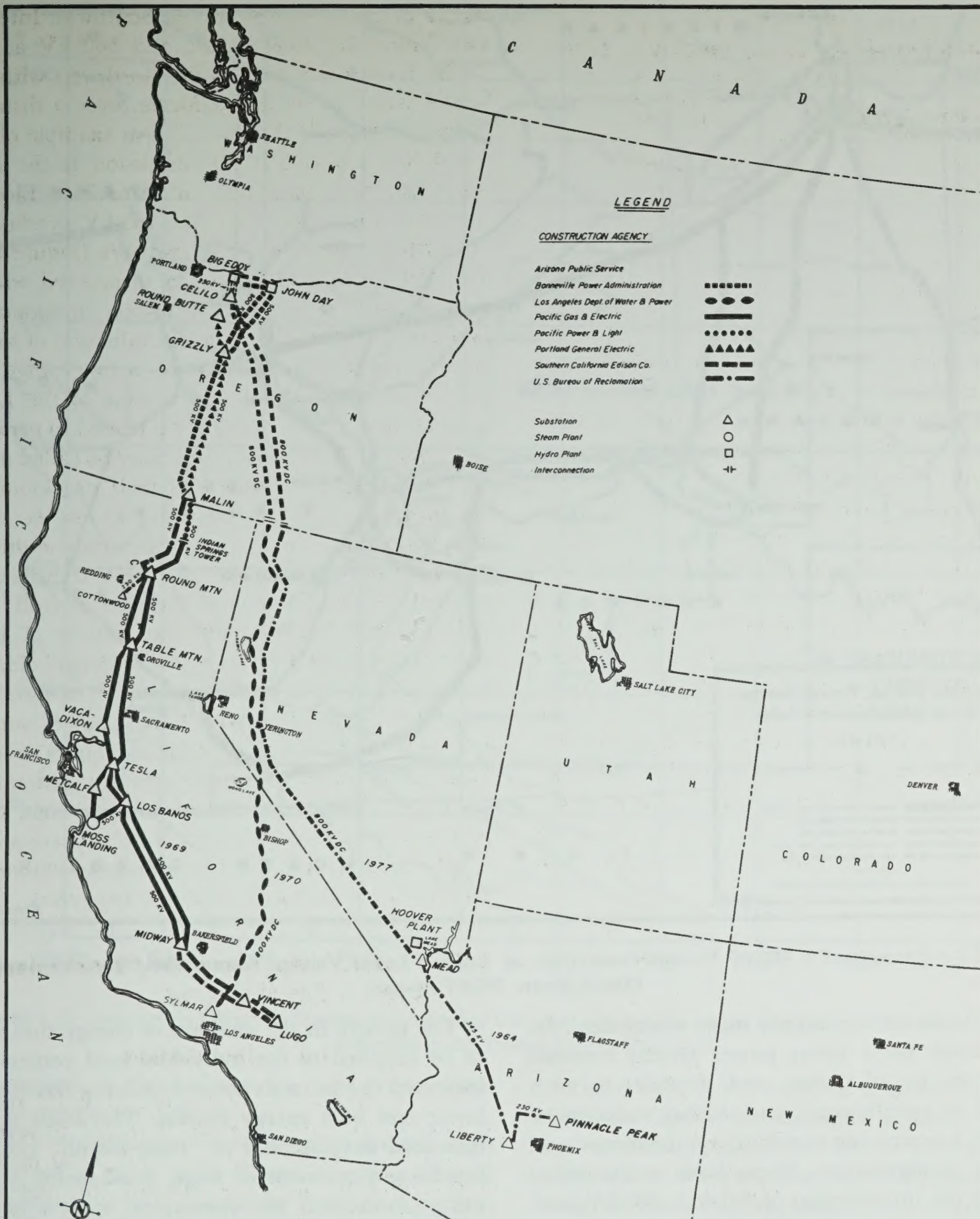

FIGURE 1.2.—Example of EHV Interconnection Between Areas.

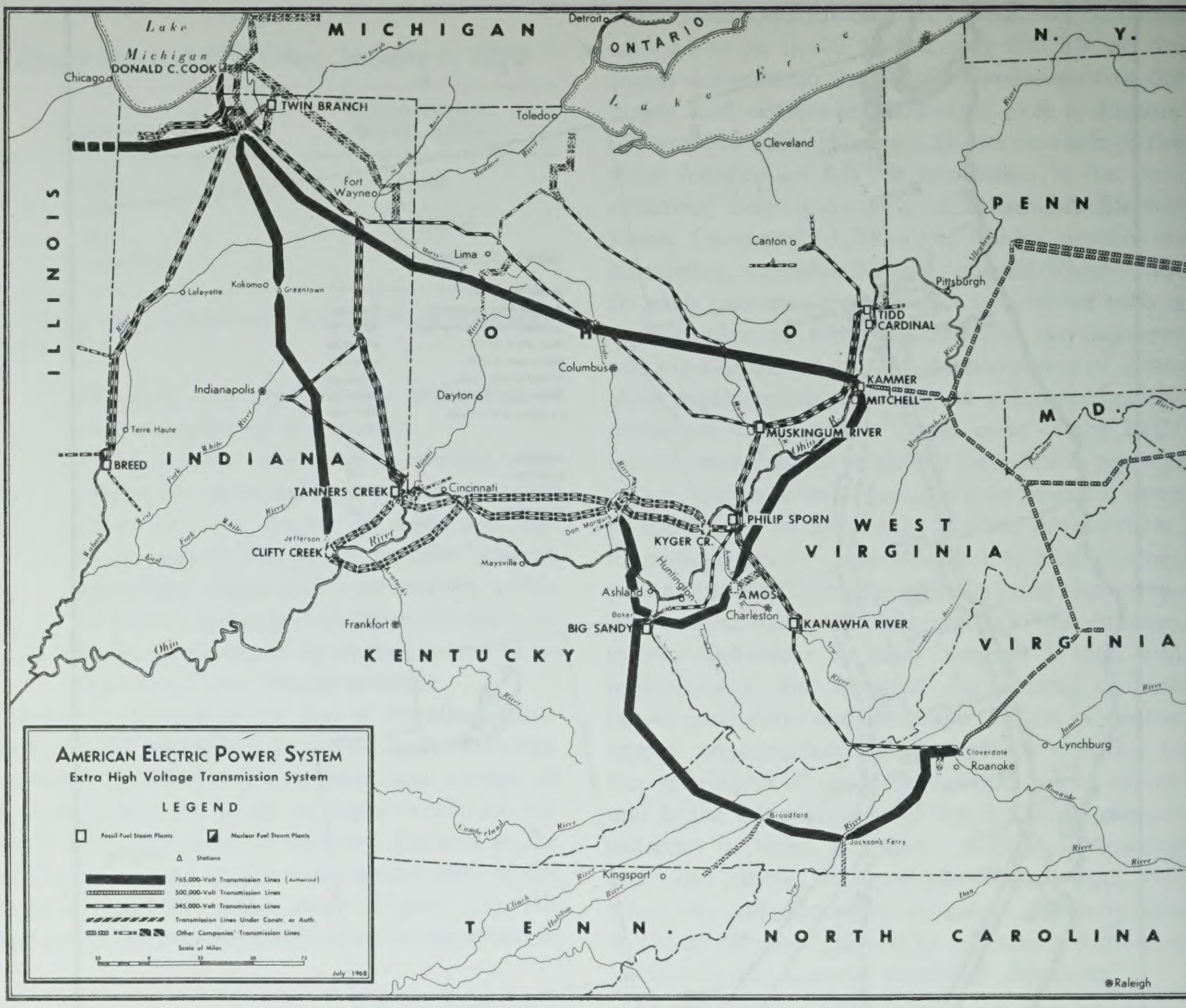

FIGURE 1.3.—Example of a Higher Voltage Overlay on an Existing Lower Voltage Transmission Network—American Electric Power 765-kV System.

mission becomes intrinsically more economical. Its introduction on a given power system becomes then a matter of timing and depends in each instance on specific conditions such as transmission distance, transmission capability requirements, and network configuration. These basic relationships underlie the introduction of 345-kV, 500-kV, and 765-kV transmission in the United States today and ultra-high-voltage (UHV—above 800 kV) levels in the future.

1.5.3 Generating Capacity Economics

The technical feasibility and economic attractiveness of concentrating increasingly large blocks of generating capacity in single units and plants has created requirements for similar concentration of transmission capability on a single transmission corridor. The maximum size of generating units increased from 208 MW in 1950 to 1068 MW in 1969, with units rated 1300 MW now on order.

The growth in the amounts of energy that need to be supplied to the individual load centers has increased the attractiveness of utilizing remote but lower cost bulk energy sources. This leads to the increased development of "mine-mouth" projects involving placement of large, fossil-fueled generating plants near the economical sources of fuel and transporting their electric energy output to remote load centers via EHV lines.

1.5.4 Availability of Land and Rights-of-Way

From several viewpoints, the amount of land used for transmission should be limited. Remaining, undeveloped land must meet the demands of agricultural, industrial, residential, and recreational needs of a growing population. The increasing use of land for highways, industry, airports, and other sometimes unattractive purposes has sharpened public opposition to such use. This has made the

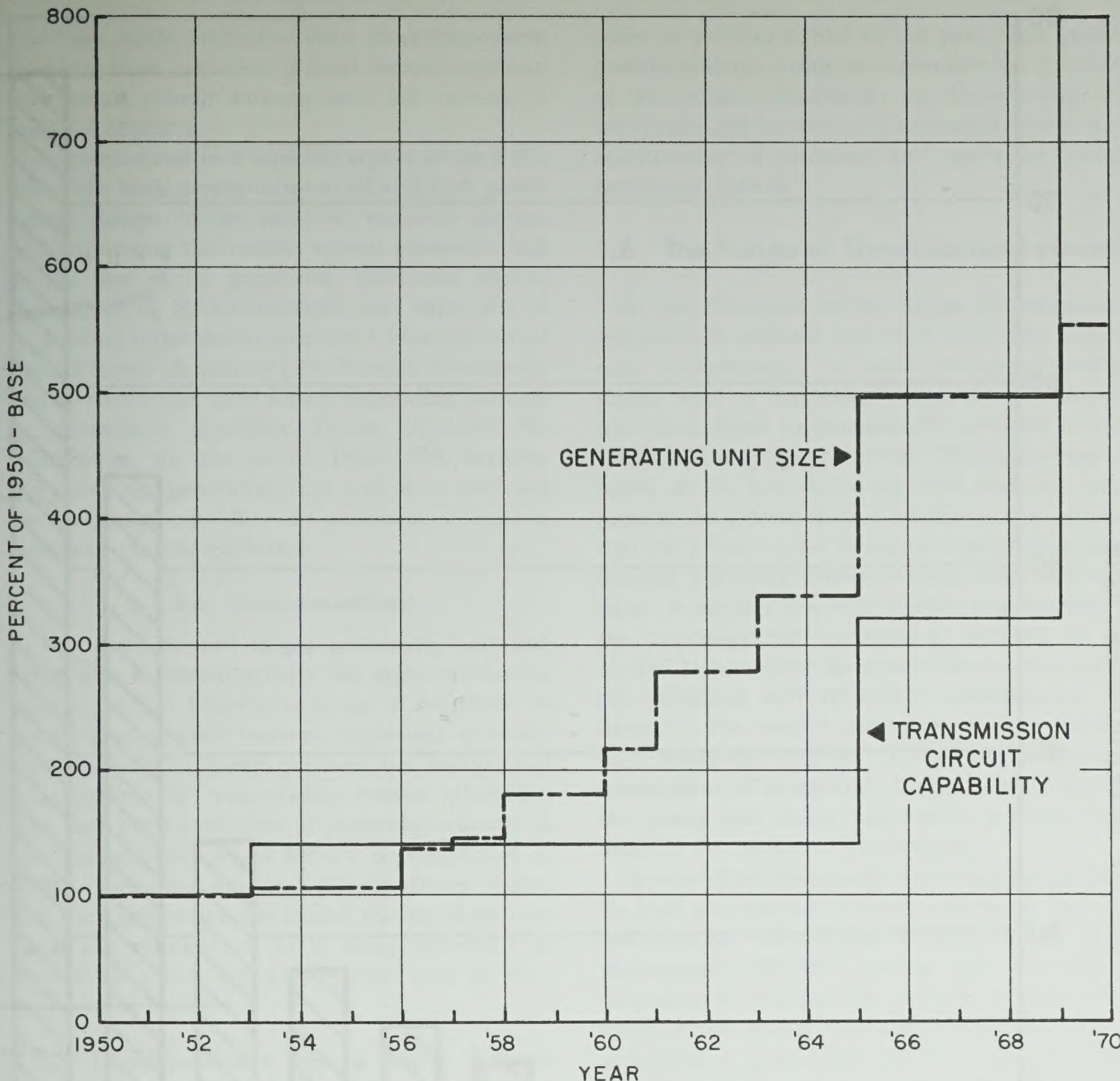

FIGURE 1.4.—Relationship Between Maximum Generating Unit Size and the Maximum Capability of Transmission Circuits in Service in the United States, 1950–1970.

acquisition of right-of-way for new transmission lines increasingly difficult.

EHV transmission enables an improved utilization of a given right-of-way in terms of load carrying capability. Except for limitations such as thermal capacity of conductors and system stability, one 765-kV line has the equivalent load carrying capability of five 345-kV lines or thirty 138-kV lines. Spacewise, a 765-kV line requires only about 200 feet of right-of-way, as compared with about 750 feet needed for five 345-kV lines and about 3,000 feet needed for thirty 138-kV lines. Thus, 765-kV transmission reduces the land requirements for right-of-way of 345-kV transmission by 3.75 times and for 138-kV transmission by 15 times. In many parts of the country, the scarcity of rights-of-way is becoming a compelling argument for EHV transmission. Indeed, in some metropolitan areas, right-of-way for overhead transmission lines is nonexistent, and underground cable must be used. Underground transmission is discussed in Chapter 7 of this report, as well as in a separate report to the FPC.[3]

1.5.5 Reliability Considerations

Reliability of electric power supply has been a major concern of the electric power industry for many years; however, the rapid growth in electric energy use and the increasing dependence of all consumers on the continuity of electric power sup-

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See footnote References, end of Chapter.

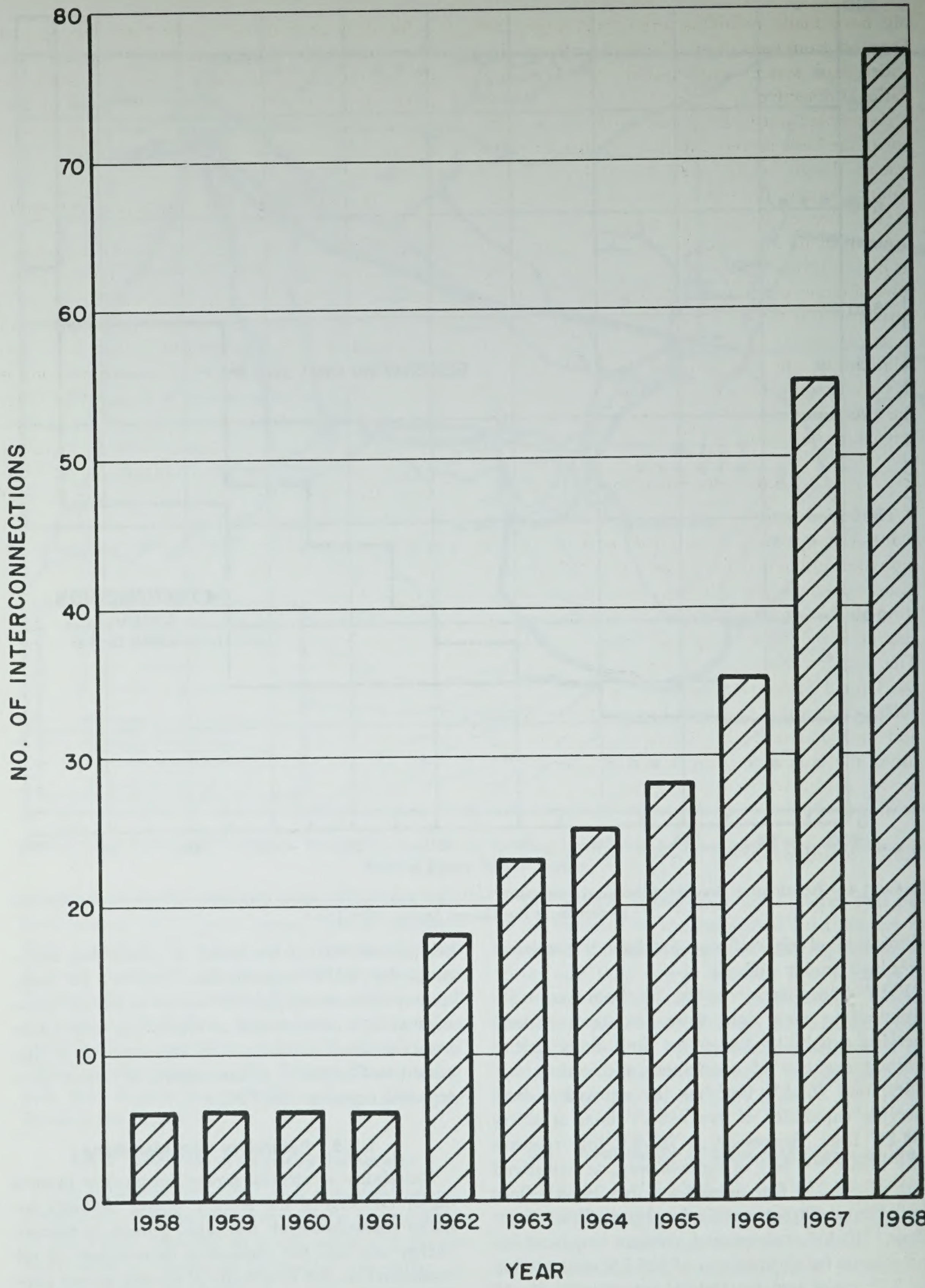

FIGURE 1.5.—EHV Interconnections in Service in the United States, 1958–1968.

ply have made reliability even more important. Freedom from cascading of local disturbances into widespread system interruptions has become a national objective.

As pointed out in a separate report to the FPC, one of the basic prerequisites to reliable bulk power system design is the need to maintain proper balance among the various system elements, such as the size of its generating units and plants, strength of its interconnections, and capability of its internal transmission channels.[4] Thus, the trend toward larger generating units because of economy carries with it the need for corresponding increase in transmission capability. Figure 1.4 shows this relationship, for the period 1950–1970, between the maximum generating unit and plant sizes and the maximum capability of transmission circuits in service in the United States.

1.5.6 Interconnections

The trend toward larger generating unit and plant sizes increased greatly the opportunities for interconnection benefits in terms of reduction in installed generation reserves, improved economy through the interchange of power and energy, and enhancement of transmission system reliability. The first interconnection at extra-high-voltage in the United States was a 345-kV tie established in 1958 between the American Electric Power system and the Commonwealth Edison system. Since that time, the number of EHV interconnections in service has grown impressively from year to year, as shown in Figure 1.5.

1.5.7 Interdependence Among Power Systems

One of the consequences of EHV transmission development in various parts of the country is the increasing interdependence among power systems constituting the interconnected transmission network. Because the equivalent reactance of a 765-kV line is but $1/5$ that of a 345-kV line and only $1/30$ that of a 138-kV line, a 765-kV line tying two points that are, say, 300 miles apart has an electric equivalent distance corresponding to only 60 miles at 345 kV and merely 10 miles at 138 kV. Thus, an EHV network spreading over many hundreds of miles shrinks the electrical distances between various load centers and generating sources to the equivalence of only a few miles at lower voltages. The practical consequence of this is that a disturbance at one point of the interconnected network has a much greater effect many hundreds of miles away than it had in the past. This greater interdependence tends to accentuate the existence of transmission bottlenecks anywhere within the interconnected network and necessitates far greater coordination of planning and operation among individual systems.

See footnote References, end of Chapter.

1.6 The Future of Transmission Systems

In this discussion on the future of transmission systems, it is assumed that there will be no unforeseen breakthroughs in small energy conversion plants, such as fuel cells, which would allow an individual home to economically generate its own electrical energy requirements. This assumption is based on the best knowledge and scientific judgment at the present time. It implies a basic premise that the present trend to larger, central generating stations supplying ever-increasing loads will continue. It implies also that further development of the interconnected transmission network in the United States will be dictated in the years ahead by the economic and reliability considerations inherent in the central generating station concept. As a result, the need for effective and economical transmission of increasingly larger amounts of electric power and energy will remain a major challenge to the electric utility industry.

In view of the continually increasing competition for land and interest in scenic values, the need for underground transmission facilities will be more pronounced with each passing year. The cost of underground transmission today is so high compared to the cost of overhead systems that undergrounding is undertaken only in downtown areas, under conditions of very high right-of-way costs for overhead transmission, or for unusual environmental conditions and esthetic demands. In order to meet these certain demands of the future, the electric utility industry may continue and accelerate its efforts to find ways of reducing the cost of underground systems. In spite of some expected cost reduction for the transmission of electric power underground, however, there will continue to be many areas where the placing of existing or of new transmission systems underground will be neither economical nor practical for many years.

The present trend toward larger generating units and plants can be expected to continue into the future for most, if not all, of the next twenty years. To begin with, the economies of scale are inherently more pronounced with nuclear generating units than with conventional, fossil-fired units. This means that as an increasingly greater percent of

total generating capacity is made up of nuclear units, the average size of generating units being installed by the individual utility systems across the country is bound to increase also. This trend will be facilitated by (1) continued growth in demand, resulting in each of the growing systems, or groups of systems, being able to accommodate increasingly larger sizes of generating units, and (2) by the increasing scarcity of land, encouraging fuller utilization of available plant sites through the installation of larger blocks of generating capacity at each site.

Given the continued trend toward larger generating units and plants, the trend toward stronger interconnections among power systems will likewise continue in an effort to provide day-to-day operating reliability and to minimize required installed generating capacity reserves. As a result, the interdependence among interconnected power systems will continue to increase during the years ahead.

It is evident from the above discussion that the extent to which the electric power industry will be able to meet the needs and challenges of the future will depend to a very large extent on continued rapid advances in the technology of EHV transmission. The considerations of growth in demand, reliability requirements, generating capacity economics, and interconnection benefits not only influence the need for further EHV transmission development, but also are, in turn, being influenced by what is actually technically and economically feasible in the area of EHV transmission applications. The technical and economic feasibility of further advances in EHV technology, on the other hand, can be achieved—in terms of higher transmission voltages and capabilities, better and less costly equipment, and sounder tools for analysis—only through concerted research and development efforts on the part of the electric power industry.

The more important considerations affecting the technical and economic feasibility of further advances in EHV transmission system development include: control of steady-state and switching-surge overvoltages, system stability, system communications, advanced control and dispatch, utilization of EHV dc transmission, development of underground transmission technology at EHV levels of voltage, and the development of the necessary analytical tools and methods. These factors are discussed elsewhere in this report.

Yet another factor essential to EHV transmission system development, which is sometimes taken for granted, is the availability of top quality, highly trained, creative people to implement the necessary research and development programs. It would be a serious mistake to assume that these specialists will be available by chance. Rather, there must be close cooperation between the power industry and universities to assure an adequate flow of qualified engineering graduates, including those having advanced degrees, into these areas.

References

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2. *EHV Transmission Line Reference Book*, Edison Electric Institute, Publication No. 68-900, 1968
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CHAPTER 2. AC OVERHEAD TRANSMISSION LINES

2.1 Voltage Trends

Increased public pressure to minimize obtrusion of transmission lines and the economic incentives to make maximum use of rights-of-way and to transmit large blocks of power reliably over long distances with the minimum number of lines have accelerated the trend toward higher transmission voltages. Many transmission lines now operate at 500 kV and 765 kV. Development work is now proceeding on overhead transmission above 1000 kV, and voltages as high as 1500 kV are being considered.

Although voltage levels up to 1500 kV will probably be needed in the future to handle greatly increased amounts of power on one right-of-way, some basic changes in design criteria are needed to make these voltages practical. At these levels, insulation requirements are determined by contamination and by switching surges. Present research indicates that contamination becomes an increasingly critical factor at UHV. Preliminary tests have shown that at these extremely high voltages a relatively large increase in tower dimensions produces only a small increase in flashover voltage. This is illustrated in Figure 2.1. The design of lines up to about 1100 kV appears technically feasible but does require additional refinements in air insulation systems to assure an optimal economic design. Above this voltage, basic data on the behavior of long air gaps with and without insulators needs to be extended. Figure 2.1 illustrates the nonlinearity between the insulation strength (critical flashover voltage) of a V-string and the horizontal distance between the conductor and tower for positive switching surges. This nonlinearity becomes more critical at UHV levels. The curve for dry conditions represents the maximum CFO possible with a specific horizontal strike distance. The ratios of withstand-to-CFO and wet-to-dry flashover vary with the ratio of insulator string length-to-strike distance, but the values shown on Figure 2.1 are typical of today's tower designs. Although more research is needed to extend this data, it appears that if an 1100-kv line is feasible at a surge level of 1.8 to 2.0 per unit (pu) under wet conditions, then 1500-kV might also be feasible at a surge level of 1.3 to 1.5 pu.

Every effort must be made to reduce switching surge levels and trend them downward as operating voltages climb. Figure 2.2 shows the effect of switching surges on tower designs similar to those used today. If surges can be reduced to values less than 1.5 pu by various techniques (such as use of multistep resistor breakers), a lower limit may be set by power frequency overvoltages. It is suggested that structure dimensions may be reduced from the conventional designs of Figure 2.2 by unconventional arrangements or by breakthroughs in means of increasing dielectric strength under adverse conditions, including contamination.

As the industry progresses to transmission voltages above 765 kV, standard voltage levels should be adopted. In selecting a new voltage for a power system, past practice has been to choose a voltage level which is about twice the system's highest existing transmission voltage. If this practice were continued, 1000 kV would be adopted for overlaying 500-kV systems and 1500 kV for 765-kV systems.

Some consideration has been given to selecting a single level which would be suitable for overlaying 500 kV and 765 kV. There are advantages and disadvantages in selecting a single voltage level. The chief advantages are that equipment and line designs would have to be developed for one voltage only and that major systems could be interconnected without voltage transformation. The disadvantage is that a single voltage may not be the best voltage to serve both 500-kV and 765-kV systems. The growth pattern on a 500-kV system may be such that the capacity of 1300–1500 kV lines could not be fully utilized until several years after installation. On the other hand, lines as low as 1300 kV on a 765-kV system may become loaded to full capacity in too short a time.

Adoption of voltage levels above 765 kV is a complicated problem requiring detailed economic and technical studies before decisions can be reached. As an example, the limits of practical air

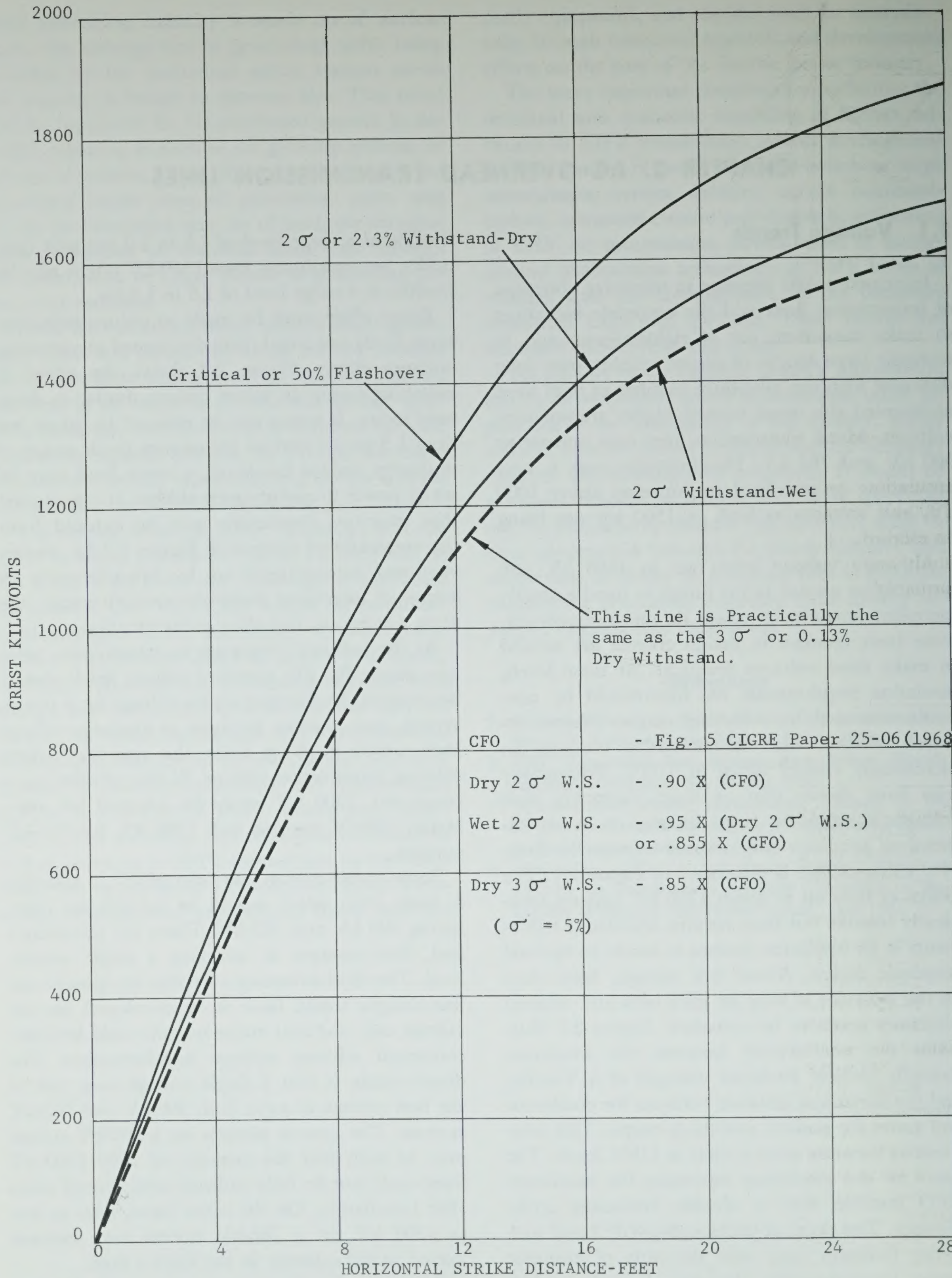


FIGURE 2.1.—Maximum Critical Flashover Voltage of V-String in a Window, Wet and Dry Conditions.

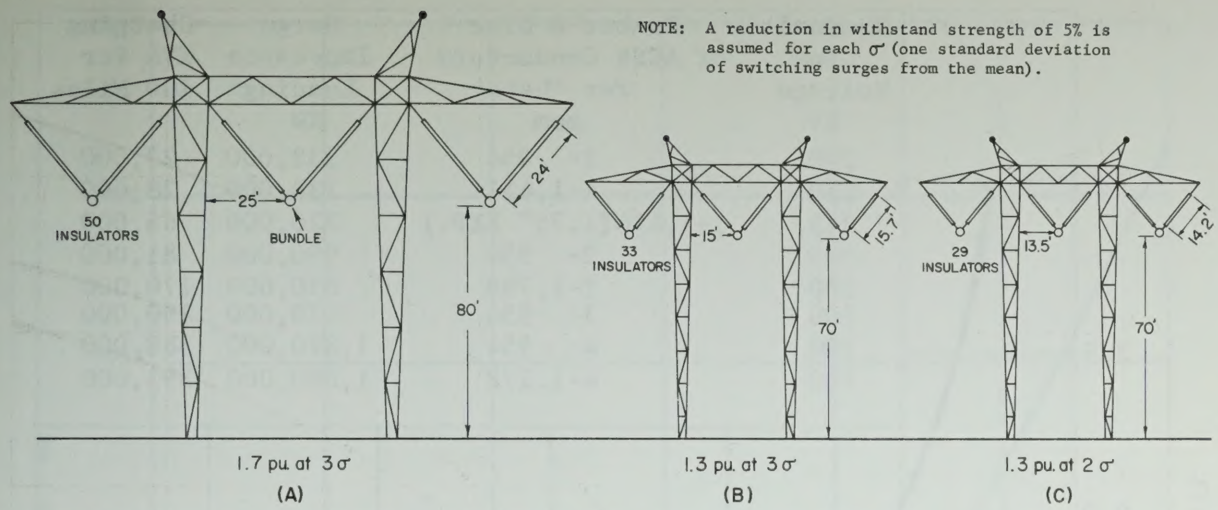


FIGURE 2.2.—Effect of Changes in Switching Surge Design Criteria on 1100-kV Transmission Line Towers.

insulation systems may not be too far above the 1300-kV level and could be the determining factor in establishing a transmission voltage level. Serious study and research efforts must be devoted to these problems.

2.2 Cost of Overhead Lines

Because 230-kV and 345-kV lines are in general use and their costs were discussed in the 1964 National Power Survey,[1] cost data for lines at these

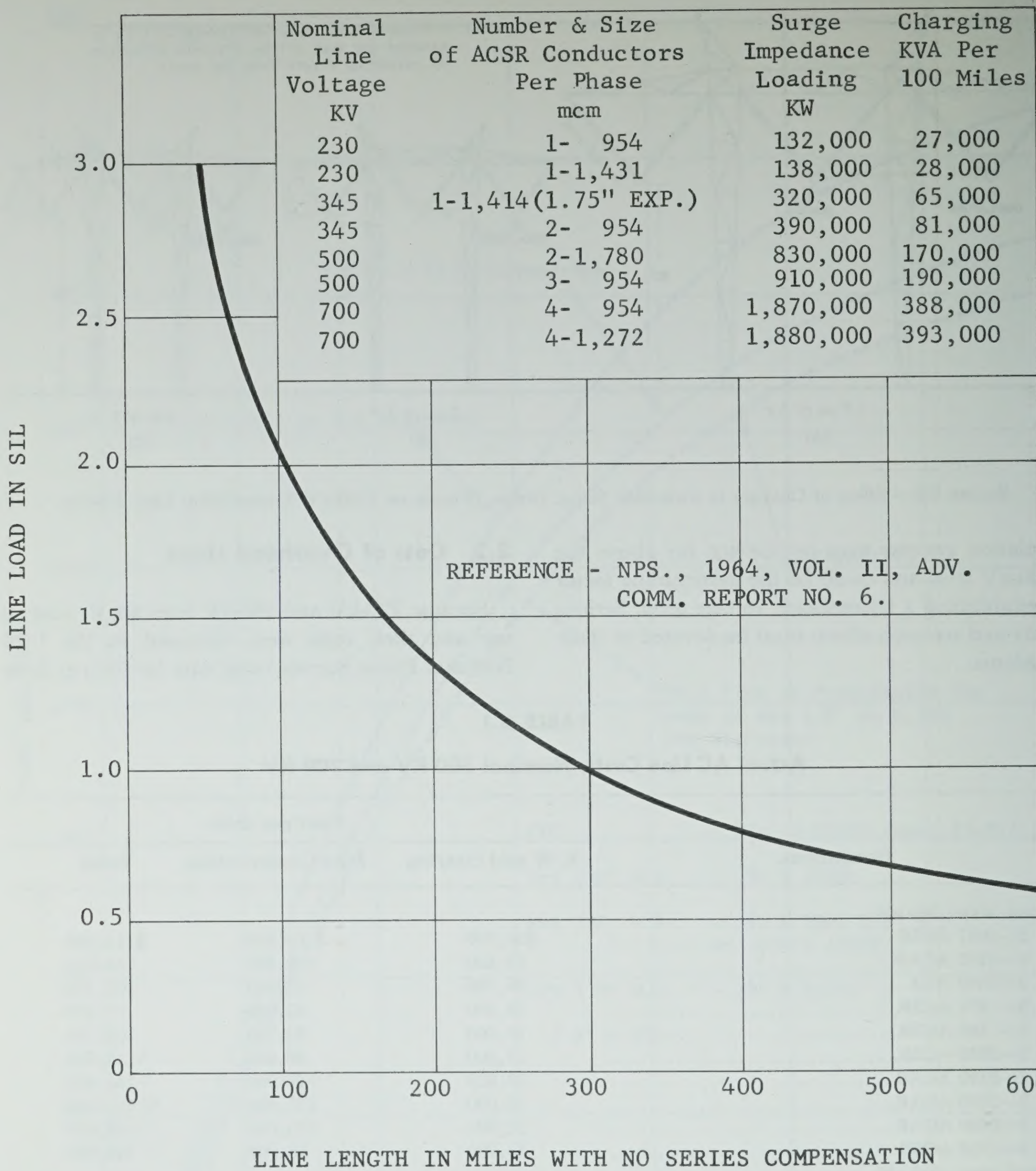
TABLE 2.1

Actual AC Line Costs, Nominal 500 KV and 700 KV

Conductors	Cost per mile: R/W and clearing	Cost per mile: Line Construction	Cost per mile: Total
Eastern area—500 kV:			
2—2037 ACSR	$30,700	$ 80,800	$111,500
2—2493 ACAR	13,500	128,500	142,000
2—2049 5005	16,700	85,800	102,500
3— 971 ACSR	12,400	65,300	77,400
4— 583 ACSR	10,000	95,500	105,500
2—2032 ACSR	17,000	98,000	[1] 115,000
2—2490 ACAR	20,000	142,000	[1] 162,000
2—2490 ACAR	59,000	272,000	[1,2] 331,000
2—2500 ACAR	22,000	118,000	[1] 140,000
3— 954 ACSR	12,000	95,000	[1] 107,000
Central area—500 kV:			
3— 954 ACSR		84,200	
3—1024 ACAR	24,000	95,600	119,600
Western area—500 kV:			
2—1780 ACSR	7,100	72,200	79,300
2—1852 ACSR		82,000	
2—2156 ACSR	25,000	93,900	118,900
2—2156 ACSR	2,000	124,000	[1,3] 126,000
700 kV:			
Average of 735 kV and 765 kV lines	18,700	146,300	[4] 165,000

[1] Latest data—other data prior to 1969.
[2] Line near urban center.
[3] Desert construction.
[4] Includes line sections built over 4-year span.

See footnote References, end of Chapter.



Nominal Line Voltage KV	Number & Size of ACSR Conductors Per Phase mcm	Surge Impedance Loading KW	Charging KVA Per 100 Miles
230	1- 954	132,000	27,000
230	1-1,431	138,000	28,000
345	1-1,414(1.75" EXP.)	320,000	65,000
345	2- 954	390,000	81,000
500	2-1,780	830,000	170,000
500	3- 954	910,000	190,000
700	4- 954	1,870,000	388,000
700	4-1,272	1,880,000	393,000

FIGURE 2.3.—Transmission Line Capability in Terms of Surge Impedance Loading.

voltage levels are not included. However, it must be recognized that the 230–345 kV construction cost has increased considerably since the time of the 1964 survey.

The actual costs of several 500-kV and 700-kV overhead transmission lines are shown in Table 2.1. These values are the average for lines in different areas of the country; however, the cost for any particular line may vary rather widely from the values shown. In urban areas, not only are right-of way costs higher, but also line costs are higher because of the larger number of angle towers, increased clearance requirements, foundation problems, and esthetic considerations. Terrain, conductor size, and labor costs have major effects. Because of the wide variation in costs of similar lines, no attempt has been made to establish estimating data. The table is intended only to give relative values.

Representative EHV line costs have been found to be approximately proportional to voltage. This assumes the variables are held constant since the

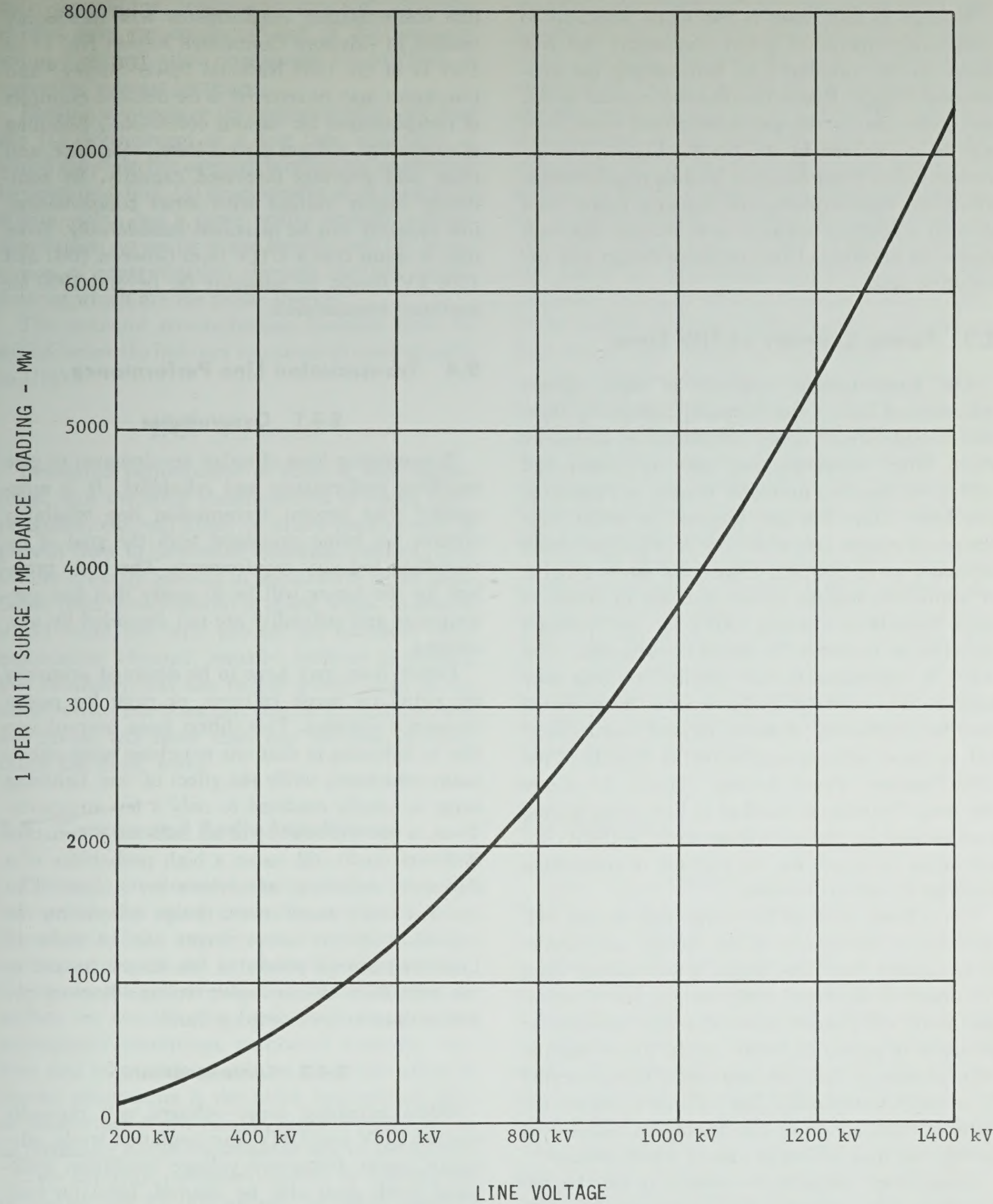


FIGURE 2.4. Typical Line Loadings 1 PU SIL in Megawatts by Voltage.

costs of new lines are influenced by factors such as location, population density, geography and environment. This linear relationship between costs and voltage, however, does not hold for voltages below 230 kV and may not hold for voltages higher than those for which actual costs are available or firm designs made. In any case, to hold costs to be proportional to voltage for lines above 765 kV, it will be necessary to control surge overvoltages to values closer to the power frequency level. In fact, the linear relationship between costs and voltage below 765 kV depends upon the reduction of relative overvoltages as the system voltage is increased.

Savings in line losses is not alone sufficient to justify the expense of larger conductors but is a factor to be considered in determining the economical design. Radio interference, corona losses, and losses due to the grounded shield wires must also be considered in the design. Losses, line investment, line compensation, loading requirements, insulation requirements, and stability limits react in such a complex manner as to dictate thorough studies in selection of the optimum design and the resulting cost.

2.3 Power Capacity of EHV Lines

The power-transfer capacity of high voltage transmission lines is not normally limited by thermal considerations unless the circuit is unusually short. Other considerations, such as corona and radio interference, normally dictate a conductor size larger than the size imposed by other constraints of system operation. For lines without series capacitor compensation, Figure 2.3 shows a curve of allowable loading versus distance in terms of surge impedance loading (SIL) for line voltages presently in operation or under construction. This curve is approximate, and detailed analysis may indicate that loadings different from those shown may be satisfactory. A more detailed treatment of SIL at these voltages is presented in Part II of the 1964 National Power Survey.[2] Figure 2.4 shows the surge impedance loading of lines with typical construction for various voltage levels, without consideration of length for the purpose of comparing loadings at various voltages.

For a fixed value of line surge impedance, SIL increases as the square of the voltage magnitude. Even though there may be an upper voltage limit for practical overhead lines, voltage levels within that limit will provide power-transfer capacity far in excess of apparent future needs. There may be other reasons to limit the amount of power carried by a single transmission line such as transient stability considerations or the maximum amount of power that may be lost in case of a line outage.

If increased capacity is needed, it can be accomplished by adding series compensation, which reduces the effective electrical line length so that the line can be operated at a higher load than shown on the curve of Figure 2.3. (EHV ac transmission line compensation is a subject which is adequately covered in existing literature. Also, the means for making a first approximation for EHV line compensation requirements was thoroughly treated in Advisory Committee Report No. 14 of Part II of the 1964 National Power Survey,[3] and this report may be referred to for detailed examples of compensation for various conditions.) Bundling of conductors reduces corona losses, reactance, and noise and provides increased capacity. By combining higher voltage with series compensation, line capacity can be increased considerably. From this, it seems that a UHV level between 1000 and 1500 kV should be adequate far beyond 1990 for overhead transmission.

See footnote References, end of Chapter.

2.4 Transmission Line Performance

2.4.1 Overvoltages

Transmission lines of today are designed to give excellent performance and reliability. It is noteworthy that present transmission line reliability criteria are being examined with the goal of establishing industry requirements. The basic problem for the future will be to assure that line performance and reliability are not degraded by new designs.

Future lines may have to be designed primarily for switching surge voltages, or even for power frequency voltages. This differs from overvoltages due to lightning in that one switching surge affects many structures, while the effect of one lightning surge is usually confined to only a few structures. Thus, a low probability of an individual structure flashover could still mean a high probability of a flashover occurring somewhere on a line. This forces a much more severe design criteria on the insulation system unless surges can be reduced. Lightning should present a less severe hazard to the reliability of the higher voltage lines of the future than to lower voltage lines.

2.4.2 Contamination

While switching surge voltages will normally control EHV and UHV line insulation levels, adequate power frequency voltage insulation withstand levels must also be assured. Insulator contamination interacting with moisture from dew, fog, or mist is a cause of power frequency voltage flashover. Insulators on overhead transmission lines and terminal equipment are being exposed to more contamination yearly. As insulator strings and stacks become longer at EHV and UHV levels, the voltage distribution across them becomes even

See footnote References, end of Chapter.

more nonuniform, resulting in very high dielectric stresses near the conductor end of the insulator string. Contamination compounds the problem as operating voltages increase.

Possible solutions to the contamination problem are (1) development of a new type insulation in which the dielectric strength is relatively unaffected by contamination, (2) development of an insulation system which has a more nearly uniform voltage distribution across its entire length, and (3) elimination of contamination through controls on industries which are the prime sources.

The insulator contamination problem must be solved before the industry can proceed economically to UHV.

2.4.3 Economics

Economic performance of lines is well understood, and the same considerations of losses, compensation, etc. will apply to future lines as well as present lines to determine economic designs. One feature recently gaining in application is the insulation (and transposition) of shield wires. Insulated shield wires not only provide an excellent communication channel, usually without degrading line reliability, but also reduce power losses in the shield wires. For lines carrying large currents, this loss saving will more than pay the cost for insulating the shield wires.

2.5 Corona and Radio Interference

Corona is an electrical discharge that occurs at the surface of a transmission line conductor when the electric field intensity at the surface of the conductor exceeds the breakdown strength of air. Contaminants or irregularities on the conductor surface are contributing factors to corona, as are atmospheric conditions, conductor material, and type and magnitude of voltage. A serious effect of corona phenomena is the radio interference (RI) or noise which it generates in received radio signals in proximity to the transmission line or substation.

Two excellent published sources of information on corona and RI that include the latest results of research at the 500-kV and 700-kV levels are the EEI EHV Transmission Line Reference Book[4] and the IEEE Committee Report on Transmission System Radio Influence.[5]

In addition to the RI effects, there are other aspects of corona phenomena that are of importance at EHV and UHV levels. One of these is the magnitude of the corona loss with its attendant power demand requirements, and another is the relationship between system overvoltages and their accompanying corona currents. While fair-weather corona losses in the order of 5 kW per 3-phase mile in the 500-kV to 700-kV line class present no serious problems, foul-weather corona losses are on the order of 500 kW or higher per 3-phase mile at the same voltage level. Losses of this magnitude can result in appreciable energy capacity cost penalties. Another effect of corona is that it produces audible noise in foul weather. This factor may control line design in some areas.

Corona losses may be beneficial in attenuating switching-surge overvoltages to a degree that will permit lower line insulation. Preliminary test and analytical results for the 500-kV and 700-kV class of line support this hope, although definitive quantitative results are not yet available. More research effort is needed in this area.

Although there are seasonal and daily variations in the fair-weather RI levels, guidelines have been developed for line designs that will yield acceptable RI levels. Steps that can be taken to reduce RI level include proper conductor sizing and bundling to control electric field strengths and careful stringing of the conductors during line construction to minimize surface marring.

2.6 Esthetics

Since the publication of the National Power Survey in 1964, the appearance of overhead electric lines, both distribution and transmission, has been a subject of criticism by the public in many parts of our nation. One solution would be to construct underground lines, and, for this reason, much development work has been done on underground cables. However, there are situations where placing a transmission line underground could increase the visual and physical impact upon the environment. The construction of an underground transmission line through timbered country could result in a wide scar with resulting damage to the environment. The United States Departments of Interior and Agriculture publication entitled "Environmental Criteria for Electric Transmission Systems" provides reference guidelines for this problem. While the industry has been able to materially reduce the cost of lower voltage underground systems, there has been no major breakthrough on the cost of underground transmission systems. At the

See footnote References, end of Chapter.

present time, research projects underway are aimed at reducing the cost of underground transmission facilities, but it will probably be several years before any major results are obtained.

Realizing that it would take much time to develop underground facilities to economically handle the transmission esthetics problem, the Edison Electric Institute (EEI), in conjunction with the Electric Research Council, sponsored a research program to improve the appearance of overhead transmission facilities. This program was headed by a group of utility engineers who employed an architectural design organization to design transmission structures from an esthetic viewpoint. They also employed an engineering firm to check the practicability of the structure designs. This work was completed early in 1968 and a book was published entitled "Electric Transmission Structures" which is available through the EEI.[6] In addition to the book, copies of a small brochure, a movie, slides, and microfilms of the tower drawings are available to the industry.[6] The designs were made to fit into various terrains and neighborhoods and to be esthetically acceptable. No one design can be used in all locations. These designs are intended to improve the appearance of overhead lines from an architectural standpoint in certain areas today and also be esthetically acceptable in the future. In general, the structures are somewhat more expensive than conventional latticed towers but are much less expensive than underground transmission cables which are available today. It is realized that these structures will not be needed in all areas and that the conventional latticed towers can still be used in many locations.

For the lower transmission voltages, single wood poles with curved arms for both single and double circuits are practical in many areas. Likewise, single steel and concrete poles with curved arms can also be used for improved appearance where needed. Wood, steel, or concrete "H"-frame structures can continue to be used in many areas. As is brought out in the EEI designs, many structural configurations can be used which give an appearance of gracefulness and simplicity. Occasionally, the appearance of an overhead transmission line can be improved through the use of several types of structures in the same line, rather than having all structures of the same general type.

The use of color also plays an important part in improving the esthetics of overhead transmission structures. Color can be accomplished by painting, anodizing, or through the use of rust-resistant steels. The color used should depend on the location of the structures—whether they are in the mountains or plains, in wooded areas, on sand beaches, or in the desert. Aluminum towers, because of their lighter weight, have been used advantageously for helicopter installation in inaccessible areas. Unfortunately, their shiny surfaces are objectionable, particularly in forested areas, and would require painting or treatment to blend them into their environment.

The selection of routes for overhead transmission lines is very important. In crossing main highways, an effort should be made to have the lines cross in wooded areas and nearly at right angles to the road. Shrubs and low growing trees can be planted on the right-of-way to hide it at road crossings. In mountainous country, lines should cross the ridges in such a manner that the wide, cleared areas are not seen from a distance.

Park and recreation activities, as part of a local government's open space system, offer good possibilities for joint use of transmission line rights-of-way. Many park and landscaping uses, including several varieties of low growing trees, are compatible with a transmission line. Thus, a "longitudinal park," that is, one running parallel to and underneath a transmission line, could be developed for the equestrian, bicyclist, and pedestrian, subject to safety requirements. This not only could recapture use of lost open space but would tend to render a transmission line less visible.

Much has been said about utility corridors, namely, locations where railroads, highways, gas lines, oil lines, electric lines, and others follow a common right-of-way. This is very good in commercial and industrial areas. In most other areas, however, the separation of the lines would be less objectionable than several lines on one right-of-way, provided that the lines could not be seen at the same time. Double-circuit construction should be considered if two or more lines must be constructed close together through any given area.

The conclusion is drawn that there is no set pattern for the location, design, and construction of transmission structures to make them acceptable by the public from an esthetics standpoint. One area may accept a design which is entirely unacceptable to an area in a different part of the country. This also applies to the color of the structure. Appearance is something that will continually have to be emphasized since it will be many years before all overhead transmission lines can economically be replaced with underground cables.

See footnote References, end of Chapter.

References

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CHAPTER 3. AC TERMINAL EQUIPMENT

3.1 Equipment Insulation and Lightning Arresters

3.1.1 Introduction

The insulation systems used in transmission substations can be classified into one of two groups: (1) external, with air as the principal constituent, or (2) internal, usually made up of solids, alone or in some combination with oil or compressed gas. The application and protection philosophies for the external insulation may economically include greater risks of failure than for the internal systems. This stems, of course, from the self-healing properties of air versus the usual permanent and severe damage after an internal failure.

As transmission system voltage levels rise, overvoltages attain greater significance for both operating performance and costs of substation insulations and equipment. Modern lightning arresters effectively suppress both lightning and switching surges to protect substation insulations. However, their protective levels are limited by the endurance of the arrester to overvoltage effects. The evolution of lightning arresters has dramatically affected the practicality of reduced levels of transmission substation insulation systems, particularly at extra-high voltages. The practical development of ultra-high-voltage substations will depend on improved lightning arresters and upon advancements in the control of overvoltage magnitudes.

Some of the various aspects of overvoltages, insulation systems, surge protection, and insulation coordination pertaining to transmission substations are discussed in the following sections.

3.1.2 Voltage Stresses

Insulation elements of substation electrical equipment are exposed continuously to the normal power frequency system voltage and occasionally encounter excursions of system voltage or voltage surges from lightning and switching. Transmission system nominal voltages, listed in Table 3.1, column 1, are those generally used in the United States and are established as American National Standards Institute (ANSI) standard voltages.[1,2,3] The standard, however, is being revised to be consistent with the highest voltage system now in use which has a maximum design voltage of 800 kV. There are two somewhat conflicting approaches to the selection of future ultra-high-voltage (UHV) levels that are higher than those currently being used. One is to establish as the next voltage a level sufficiently high to be economic for use with all lower voltage systems. This would permit interconnection of all UHV systems (above 1000 kV) without transformation. On the other hand, it seems that some appreciable time will be required for the technical research necessary to introduce a new voltage level high enough to be used economically with a system presently operating up to 800 kV. In the meantime, some systems which are using maximum voltage levels below this will probably require a new voltage level above 800 kV before a voltage suitable for overlay on an 800 kV system is technically feasible. When a new level is introduced, it should be as high as technically and economically practical to obtain maximum useful life of the facilities.[4] Substation apparatus insulation must be designed for the maximum voltage to which it will be exposed. Column 2 of Table 3.1 lists the present standard maximum design voltages for system components.

Exposure of transmission substation insulations to lightning usually is confined to surges originating from strokes to the transmission lines. Severe direct stroke effects are avoided by overhead ground wires or tall spires in the substation and by good shielding of transmission line entrances. Consequently, the maximum lightning surges in substations approach the impulse flashover voltage of the transmission insulation. These very short duration surges (30–200 microseconds) with steep wavefronts (10 microseconds or less) can readily be suppressed by lightning arresters. Low voltage systems will be affected by lightning much more than systems whose insulation levels approach the

See footnote References, end of Chapter.

TABLE 3.1

Standard Voltages for Oil-Immersed Apparatus

Nominal	Maximum	Lowest insulation level used[1]
115	121	350
138	145	450
161	169	550
230	242	650
287	302	1300
345	362	900
500	550	1300
[2] 700	765	1800

[1] These basic impulse insulation levels apply mainly to transformers and result principally from improvements in lightning arrester characteristics. Data has been taken from various sources describing substation features.

[2] Although an ANSI preferred voltage rating, the present systems operating near this level use approximately 735 kV to 765 kV.

voltage magnitude produced by most lightning strokes.

Switching surges, discussed in Chapter 4 of this report, generally have long wavefronts (100–1500 microseconds) and durations (3000 or more microseconds). Maximum switching surge values of 3.5 per unit or more (3.5 times peak line-to-ground operating voltage) are possible for uncontrolled switching; however, one-step resistor closing breakers generally can limit these surges to 2.1 per unit or less. This has been satisfactory for EHV substations, but UHV may require further limitation to 1.5 per unit or less. Another phenomenon associated with switching operations is the maximum dynamic envelope,[5,6] which is discussed in section 4.4 of this report. This is of particular significance to lightning arrester thermal durability.

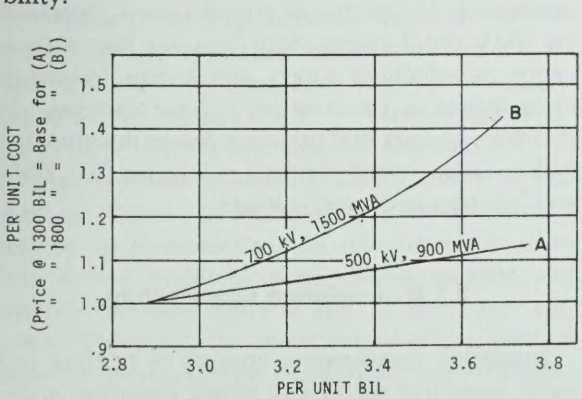

FIGURE 3.1.—Relationship of Transformer Cost to Basic Impulse Level.

See footnote References, end of Chapter.

3.1.3 Insulation Elements

Transmission substations include extensive outdoor buses and connections that rely on air and porcelain for insulating strength (just as overhead transmission lines do). The performance of these elements is discussed in Chapter 2 of this report. Support insulators and equipment bushings must become disproportionately longer for higher voltages.[7,8] Only glazed porcelain and glass, so far, have proved satisfactory for insulations exposed to varying atmospheric and contamination conditions. Considerably more research and testing is required not only to develop satisfactory new materials for lighter, less expensive insulation components but also to cope with the detrimental effects of contamination, which may become a controlling factor at UHV.[9]

Apparatus internal insulations are combinations of solid materials with either oil or compressed gas. Transformer windings are insulated by special papers, fiberboards, wood, and porcelain surrounded and saturated with oil or a gas such as sulfur-hexafluoride (SF_6). The oil or gas serves both as an insulator and coolant. Voltage gradient control measures become more elaborate with increasing voltages. Successful design and operation of UHV test transformers infers that the solid-oil insulations can be extended to UHV power transformers.

In circuit breakers, solid materials must not only insulate but some components must also provide considerable strength to mechanical shock. The oil or gas insulates and helps to cool the arcs during interruption. Oil-type breakers have predominated for applications on 230 kV and below, and some have been used at 345 kV. However, circuit breakers for EHV normally use compressed air or other gas. Extensive research and testing will be required to develop satisfactory UHV circuit breaker insulations.

3.1.4 Lightning Arresters

The role of lightning arresters for substation apparatus protection now goes considerably beyond the suppression of lightning- or impulse-type surges. Modern current-limiting gap arresters have afforded improvements in protective sparkover and discharge voltages for both impulse and switching surges.

The arrester, however, is not only vulnerable to excessive surge energy but also to steady-state and

See footnote References, end of Chapter.

dynamic overvoltages which can, by repetitive operations, cause its demise thermally. Particularly at EHV, the proper application of arresters requires thorough analytical evaluation of expected power frequency overvoltages.

At UHV levels, the duty on lightning arresters can be extreme due to switching surges. The higher voltages and longer lines greatly increase the switching surge energy to be dissipated. Further development of arresters with improved thermal characteristics will thus be of importance to UHV systems.

3.1.5 Insulation Levels

The ability of apparatus insulations to withstand surges and overvoltages is characterized by three types of voltage level ratings. These are (1) basic impulse insulation level (BIL), (2) basic switching surge level (BSL), and (3) the low (or power) frequency test voltage. The values of BIL and low frequency test voltages commonly used are given in Table 3.2.[2] Additionally, values of 83% of BIL have been assigned as the BSL values for transformers, based on tests of present design configurations. The effect of BIL rating on cost is shown in Figure 3.1 for 500-kV and 700-kV transformers.

Insulation levels for 500-kV equipment and below have been fairly well standardized. While economies can be obtained by reduction of these levels, the savings are relatively minor. At 700 kV and above, the conservatism of past protection philosophies adds considerable cost penalties, and, in the case of 1000- to 1500-kV equipment, comparable insulation levels may be impossible to reach. A new philosophy of basing the insulation level on the maximum credible voltages (with margin) that can exist on the system must be adopted. For example, impulse voltages are limited only by the protective characteristics of lightning arresters. These characteristics determine the impulse insulation levels of the devices. The switching surge insulation level in the past has also been determined by the lightning arresters. Recently, means have been devised to limit the magnitudes of switching surges caused by circuit breakers and other switching devices to levels below the arrester protective limits. The BSL's probably can be lowered to take advantage of these lower magnitude surges.

Prior to the establishment of impulse and switching surge insulation levels, all equipment insulation was verified by a low-frequency test. This test level is considerably higher than the maximum 60-Hz voltages encountered on a power system. With the advent of specific impulse and switching surge tests, the need for this relatively high, low-frequency test level may be obviated. Using the new insulation philosophy, the low-frequency test level should be determined by the maximum line-to-ground voltage, during the worst fault, with an appropriate margin. This test should be performed during a contaminated condition as defined by the appropriate standards.

With available apparatus design modifications, the switching surge and over-voltage withstand levels could be improved independent of apparatus BIL. This undoubtedly will become an important application and economic consideration, especially for UHV transformers, since lightning loses prominence to switching surges and power frequency overvoltages as the nominal voltage increases. It therefore appears that optimum future designs must look to independent standard ratings for BIL, BSL, and low-frequency test voltages.

TABLE 3.2

Transformer BIL and Associated Power Frequency Test Voltages

BIL (KV)	Power frequency test level (Line to ground KV)
350	140
450	185
550	230
650	275
750	325
900	395
1050	460
1300	575
1550	690
1800	800
2050	920
2300	1030
2550	1140
2800	1255
3050	1370

3.1.6 Insulation Coordination

Insulation coordination consists of relating impulse, switching surge, and power frequency withstand voltages of all substation electrical apparatus and the respective protective characteristics of lightning arresters, as well as other equipment. Emphasis is on the power transformer because it usually is the most expensive substation unit for

See footnote References, end of Chapter.

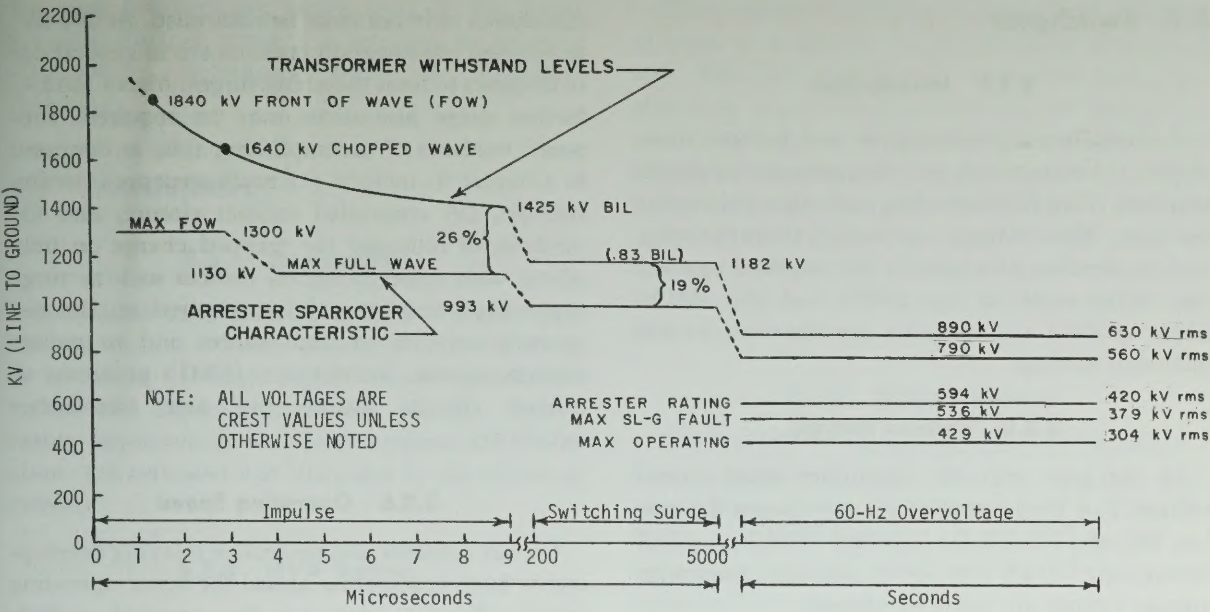

FIGURE 3.2.—Insulation Coordination Study Leading to the Choice of 1425-kV BIL for Power Transformers and Shunt Reactors.

which several BIL's are available for each nominal voltage. Generally, only a single BIL per voltage level is available for other apparatus, such as circuit breakers, and this BIL is almost always higher than that of the transformer.

An example of an insulation coordination study for a 500-kV system[10] is illustrated by the relative transformer withstand and arrester protective characteristics in Figure 3.2. In this study, the maximum operating 60-Hz voltage is assumed to be 105% of nominal. Coordination is shown in the three time regions: impulse, switching surge, and power frequency. The protective margins afforded by arrester sparkover values exceed the generally accepted minimum of 20–25% and 10–15% for impulse and switching surges, respectively. Proper application of modern arresters, together with effective line and substation shielding, generally assures that the same protective margins are maintained for the arrester discharge voltage (the product of surge current and arrester resistance).

Low-frequency insulation coordination is implied in Figure 3.2. Although the arrester would provide such protection, its operation for other than a few cycles of power-follow current will provoke thermal failure of the arrester valve elements. Therefore, the reseal rating of the arrester must exceed maximum steady-state over-voltages, as indicated by the lower curves. The increased capability of arresters to endure temporary over-voltage and 60-Hz power-follow current will be an important development to afford further BIL and BSL reductions, especially for UHV.

The focus on substation esthetics has evolved a trend toward lower profile designs. As this tends to minimize electrical ground clearances, increased attention must be devoted to maintaining safe working space for both personnel and maintenance equipment. Tests performed on conductor-man configurations are useful for EHV design evaluations.[11] Likewise, the problem of preventing sparkover of the isolating gap of an open disconnect switch during maintenance operations must be seriously considered in the design and operation of increasingly higher voltage substations.[12–15] Thus, insulation coordination, especially in the switching surge region, must assure personnel safety, as well as equipment protection, through not only the design and location of equipment, but also the effective use of lightning arresters, protective air gaps, and surge control.

Investigations are now in progress to determine the technical feasibility of UHV voltages in the order of 1000 kV to 1500 kV. Other problems that require attention and solution are (1) the establishment of equipment BSL's independent of BIL, (2) contamination, (3) further limiting the magnitude of switching surges, (4) continuing development to improve the protective characteristics of lightning arresters, and (5) the need for establishing standard voltage levels above 550 kV.

See footnote References, end of Chapter.

See footnote References, end of Chapter.

3.2 Switchgear

3.2.1 Introduction

As systems continue to grow and become more closely interconnected, the requirements of circuit breakers, disconnect switches, and other switchgear increase. New ratings, operating characteristics, and application philosophies are required to meet the utility needs of the 1970's and the 1980's. Some of these requirements are discussed in the following sections.

3.2.2 Voltage Ratings

In the past, only the maximum rated system voltage had been specified for switchgear devices, i.e., 362 and 550 kV for 345- and 500-kV nominal systems. At 700 kV and above, standard maximum voltage ratings are being developed.

3.2.3 Continuous-Current Ratings

With a few exceptions, the present maximum continuous-current rating is 3,000 amperes for switchgear equipment. At 500 kV and above, this maximum rating will probably be adequate for several years. The effect of increased EHV and UHV ties will be felt on the lower voltage systems in the form of 5,000- to 6,000-ampere continuous-current rated devices being required in the 1970's and 1980's.

3.2.4 Interrupting Ratings

Present circuit breakers have maximum symmetrical interrupting current ratings of approximately 40,000 amperes. At 345 kV and below, ratings of 60,000 and 80,000 amperes will be required in the immediate future. These higher ratings will also be needed at 500 kV, and 700 kV later on.

Present standards dictate an asymmetry factor built into the breaker based on a system X/R ratio of 15 to 20. Thus, the asymmetrical rating of a 2-cycle breaker is 1.3 times its symmetrical rating. For UHV systems and the higher capacity lower voltage systems, the X/R ratios are between 30 and 50. Breaker designers must recognize this fact in new equipment designs.

3.2.5 Switching Surge Control

To achieve the reliability and economics of reduced insulation levels mentioned previously, the switching surges generated by circuit breakers and disconnect switches must be controlled. At 500 kV, single-step pre-insertion resistors are in general use in breakers to limit switching surges. Above 765 kV, further surge limitations may be required. Proposed methods of accomplishing this, as discussed in Chapter 4, include (1) multi-step pre-insertion resistors, (2) controlled contact closure, and (3) methods of reducing the trapped charge on line. Along with these measures, devices such as surge suppression resistors will be required on the disconnect switches to limit surges and to reduce electromagnetic interference (EMI) problems in control circuits during bus and transformer switching.

3.2.6 Operating Speed

Circuit breakers and protective relaying developments have continually aimed for faster operating speeds. Present apparatus has reached a fault clearing time of 2½ cycles (2-cycle breaker plus ½-cycle relay) for most primary fault conditions. Further efforts will be exerted to reduce these interrupting times to minimize damage and shock to the system during maximum capacity faults.

3.2.7 Single Pole Reclosing

While single pole reclosing has not been widely used in this country, the obvious advantage of increased system stability, and not so obvious controlling effects on switching surge magnitudes, may lead to an increased use of the concept. Most transmission breakers will be designed for this option; however, problems of secondary arc extinction at the EHV and UHV levels must be investigated and solved before full use can be achieved.

3.2.8 Current Measurement

In dead-tank breakers, often used through 345 kV, current (amperes) is measured by relatively inexpensive bushing current transformers. With breakers of the live tank design, used for EHV systems, separately mounted current transformers are required. Conventional current transformers of this type are expensive, and some other means of measuring current is needed (see section 3.5.2).

3.2.9 Interrupting Media

For many years, oil has been the primary interrupting medium in this country. Recently, gas (either SF_6 or compressed air) has come into general use, especially at the higher voltages.

Vacuum breakers are being used in the lower voltages. Further research is required to improve interruption techniques such as solid-state switching.

3.3 Transformers

3.3.1 Introduction

Continued load growth, greater concentration of loads, and use of larger generator units will result in the need for both higher power transformer ratings and higher transmission voltages. Transformer requirements for power systems of the near future are reviewed and discussed in the following sections.

3.3.2 MVA Rating

Three-phase transformers now used on 345 kV systems are approaching ratings of 1000 MVA, and transformers rated 1300 MVA are on order. Banks comprised of single-phase units with ratings up to 1200 MVA are in service on 500 kV systems. Some operating experience has been obtained on single-phase units in ratings up to 500 MVA at 765 kV. Some 10,000 MVA of transformers for operation at 765 kV is scheduled for service in the next few years. Prototype power transformers for overhead and underground test facilities are being designed and built to operate in the 1000 to 1500 kV range.

In the future, transformer MVA ratings will continue to increase. This will present new problems in manufacturing and shipping units of the ratings required. Today, manufacturers are shipping the largest units that can be transported over the nation's railroads. Reductions in insulation levels in the past have permitted more MVA to be put in the same size package. Further insulation level reductions, however, do not offer much promise for reducing physical size appreciably in the future.

Improvements in the thermal properties of insulation systems for large power transformers now permit units to have a temperature rise of 65° C instead of the 55° C used commonly in years past. To date, only limited advantage has been taken of this development. With 65° C rise permitted, a 12% increase in unit capability is experienced. Future developments in insulation systems may permit higher temperature rises above ambient with a corresponding increase in MVA capacity for the same physical size.

There has been some experimental field assembly of units as a solution to the problem of physical size. This has ranged from segmented tank construction, where the core and coils are shipped in one piece and the bridge and superstructure are shipped in another, to complete assembly of core, coils, insulation, etc. in the field. If field assembly is to be a solution to the size limitation problem, then test methods and techniques must be developed to insure that reliability of transformers is not impaired.

3.3.3 Voltage Ratings

The first 765 kV transmission lines in this country were energized in 1969. The next voltage level above this will be in the range of 1000 to 1500 kV, which may be in service by 1980. Transformer developments must keep pace with the projected transmission voltages.

3.3.4 Insulation Levels

The economic benefits of using reduced BIL have already been discussed. The capability for further reducing the BIL becomes greater as lightning arresters are improved. The use of lower BIL places more emphasis on the problem of protecting transformers against switching surges and amplifies the need for better defined BSL's. Reducing the amount of insulation for withstanding lightning and switching surges then focuses fresh attention on the low-frequency test voltage and the ability of the transformer to withstand the normal operating voltage. The entire concept of providing insulation to withstand transient and normal operating voltages must be reevaluated as the industry progresses to higher voltages in the EHV and UHV ranges.

3.3.5 Impedances

The increase in clearances required in UHV transformers inherently causes higher impedances. High values of transformer impedance may create problems of voltage regulation and require an extension of the present standard tap ranges. High impedances may also create problems in system stability by limiting the power which can flow between systems. Consideration must be given to means of designing UHV transformers with lower impedances or of designing systems with the inherently higher transformer impedances taken into account. The possible short-circuit forces on transformer windings increase as the impedance is lowered. Because of this, the practical impedance

reductions are limited by transformer cost and reliability consideration.

3.4 Line Compensation

3.4.1 Background

Transmission line compensation is one of the tools used in system planning and design. It is a means of (a) increasing the power carrying ability of a line, (b) increasing the distance over which power can be transmitted, (c) controlling the voltage gradient on lines, (d) increasing system stability limits, and (e) effecting the best division of power between parallel lines.

Compensation is accomplished through shunt reactors, synchronous condensers, or series capacitors. Shunt reactors are necessary to improve system characteristics under light loading conditions, while series capacitors improve system characteristics under heavily loaded conditions. Synchronous condensers can be operated as either shunt reactors during light loading or as shunt capacitors during heavy loading.

3.4.2 Shunt Reactors

With long transmission lines, the line charging current can become excessive and can result in high system voltages. Shunt reactors may be employed to reduce the effects of these currents. At EHV levels, it may be advantageous to connect the required shunt reactors directly to the line. Reactors applied in this manner are oil-immersed with magnetic shielding to prevent oil-tank heating. Losses for oil-immersed reactors in sizes that are applied on EHV are in the order of 3 watts per kilovar. The magnetic circuit of grounded-wye, 3-phase reactors can be designed to make the reactance of each phase independent of the other, or coupling can be allowed which will lower the effective reactance for asymmetrical voltage conditions. This feature can be advantageous in reducing overvoltages during ground faults.

There are system applications where it would be economical to have the shunt reactor function integrated with the transformer if a design can be made that preserves desirable transformer characteristics. Elimination of the switchgear required to vary reactive power, by the development of controlled reactors, could also prove valuable to the industry. This control could either be stepped on/off or be continuous.

Also widely used are air core reactors, usually on the tertiary of power transformers. Losses in this type will be slightly higher than for the oil-immersed type.

A recent development in shunt reactors that may increase EHV system reliability and capability in the future is the insulating core shunt reactor (ICR). The ICR is constructed of modular decks containing core and coil assemblies, with each protected by individual Faraday cage static plates. The ICR is claimed to have superior internal voltage distribution under both transient and steady-state conditions and to have lower losses, less weight, and smaller size than other reactor designs.

3.4.3 Series Capacitors

Series capacitor construction is in modular form with racked individual capacitor units and with control and protective equipment mounted on a common platform which is insulated for full line-to-ground voltage. A 3-phase installation involves some multiple of three such platforms.

The voltage developed across the series units depends on line current and the capacitance of the installation. Under fault current conditions, the voltage developed across the capacitor units is prevented from rising to unacceptable levels by voltage sensitive gaps that break down and bypass the series modules. The correct functioning of these gaps is essential to proper operation of a series capacitor installation, and a considerable amount of design effort has been placed on the durability, reliability, and uniformity of their characteristics.

Capacitor units used in series application are similar in construction to those used in shunt application; however, the ratings for the units may be nonstandard because of economic considerations. The duty on the series units is quite different from shunt applications where voltage is relatively constant and overvoltages seldom encountered. In series applications, line current excursions during system transient conditions can produce overvoltages which may be below protective gap breakdowns but which may still subject the units to stresses that cause internal ionization and subsequent loss of life. Losses vary with the line loading and, because unit voltage under normal conditions is less than the unit voltage in shunt applications (in order to accomodate abnormal system current), losses for series applications are somewhat less per nameplate kVA than for shunt installations.

When the protective gaps flash over, the series capacitor installation is effectively out of service.

Restoration may take one of several forms, the simplest of which involves de-energizing the compensated line and allowing the gap to restore itself to its original electrical strength. This scheme has the disadvantage of complete loss of line capability for ½ second or more, usually at a critical time for the system.

A better scheme for transmission series-capacitor installations is one where the unfaulted line does not have to be de-energized for gap restoration. High-speed reinsertion, when fault overcurrent subsides, is accomplished either by forced deionization of the gap or by a switch that parallels the gaps just after flashover and opens when reinsertion is permissible. Reinsertion times of five cycles or less, after fault overcurrent subsides, are feasible. The recovery voltage that the reinsertion scheme must withstand is a function of the line current just before reinsertion and the system characteristics. These should be defined for the specific application.

A means is provided to automatically bypass and lock out a platform of series capacitor equipment for internal unbalance due to an excessive number of units with blown fuses or due to excessive overloads caused by system conditions. The logic circuits and equipment for performing this and other protective functions are normally located on the platforms and are therefore at line potential. Control signals for other functions are transmitted to and from platforms by devices that allow full insulation, such as pneumatic tubes or light beams. When one platform must be bypassed, the corresponding platforms are bypassed on the other phases to maintain a balanced system impedance. Maintenance on platforms is performed when all platforms are de-energized and the entire series capacitor installation is bypassed.

The modular form of series capacitor construction allows attainment of any practical voltage and current rating. Successful experience with several large 345-kV and 500-kV series capacitor stations in the western USA may increase their application elsewhere.

3.5 Metering, Relaying, and Data Recording

3.5.1 Introduction

The functions of metering, protective relaying, and data recording are extremely important to the successful operation of power transmission systems. This section discusses some of the problems, trends, and implications of these functions.

3.5.2 Instrument Transformers

Meters and protective relays utilize the secondary quantities derived from apparatus such as current transformers, potential transformers, and potential devices.

Present-day current transformers, while being quite accurate, utilize ferromagnetic core material and hence are subject to saturation. Under certain circumstances, saturation can cause misoperation of relays. To overcome some of the difficulties of conventional current transformers, new types of current transducers are being investigated. Some of the new methods being tried are a pulsed light beam, a frequency-modulated radio signal, and a polarized light beam. Devices such as these can provide a high degree of accuracy over a wide range of load currents. They are also well suited for use with solid-state relays.

Potential transformers and potential devices provide voltage sources for metering and relaying. At EHV levels, the capacitance voltage divider type of potential device provides the most economical voltage source for relaying, metering, and instrumentation.

The high accuracy output currents and voltages required for load-frequency control, telemetering, and instrumentation can be obtained from thermal converters. Transducers, some of the Hall effect type with accuracies comparable to those of thermal converters, are also being applied with the added advantage of reducing response time, a feature of importance in any high-speed control system.

Instrument transformers furnished by manufacturers in recent years have been adequate to meet the needs of expanding power systems. The trend has been toward the development of more accurate, higher voltage equipment.

3.5.3 Relaying

Protection for a high-voltage transmission system is provided by relays strategically located throughout the system and set to detect abnormal conditions such as faults, overloads, power swings, overvoltages, and undervoltages. These relays operate to isolate and/or de-energize the troubled zone of protection in such a way as to minimize both equipment damage and the effect of the disturbance on the remainder of the system.

Most high-voltage transmission lines are protected by at least one high-speed protective relay scheme, such as pilot wire, phase comparison, directional comparison, or transferred tripping. Each

of these requires a communication channel which may be wire, powerline carrier, or microwave.

The trend in the United States during the past decade has been toward the increased use of solid-state (static) components for protective relaying functions. The advantages of static relays over electromechanical relays are (1) faster operating time, (2) greater reliability, (3) greater sensitivity, (4) less burden, (5) reduced relay maintenance, (6) reduced relay test time, and (7) "complete terminal" packaging. However, static relays have the disadvantage of being more sensitive to electromagnetic interference (EMI).

With the advent of EHV systems, the proper layout of duct runs for control wiring becomes more important to limit induced surges. Shielding of control cables may be required in some installations. Both solid-state and electromechanical relays which contain solid-state components are sensitive to voltage surges.

EHV lines are commonly protected by two or three levels of relaying, including redundant pilot schemes, and some sort of backup scheme. Direct transfer tripping schemes may involve microwave, carrier, or pilot-wire channels, and when dual schemes are used they may involve combinations of these channels. Direct transfer schemes are sensitive to electromagnetic noise which may result in false tripping signals. Sometimes dual frequency-shift type channels are effective in overcoming false tripping signals, but, in general, the most secure solution is the use of adequate signal-to-noise ratios, permissive relays where possible, and, finally, a completely separate operating mode.

Transformers, shunt reactors, and buses on EHV systems are being protected by multiple relay schemes. Duplicate differential or a single differential and a sudden pressure relay are frequently applied for protection of a transformer or line-connected shunt reactor. In the absence of high-voltage breakers, these relays initiate some form of direct remote tripping. On some important buses, duplicate high-speed differential relays utilizing separate sets of current transformers are being applied. Out-of-step relays are coming into increasing use with high power interties to prevent power circuit breakers from attempting to open against high recovery voltages. A variety of schemes is in use to trip before or after the first possible maximum recovery voltage and also to divide systems as nearly as possible into self-sufficient islands.

Modern electronic components and techniques have enabled the construction of reliable, versatile relays that respond to power system quantities, such as power, frequency, or voltage according to rate of change as well as magnitude. Relays of this type have recently been put in service to effect system switching in anticipation of hazardous conditions.

Two basic schemes of automatic reclosing on transmission lines are in use: (1) high-speed reclosing and (2) checked reclosing. High-speed reclosing is used most often in conjunction with high-speed pilot relaying. Successful high-speed reclosing can be a definite asset to system stability and is in the interest of improving service to customers. However, unsuccessful reclosing, especially on a severe fault, may be detrimental to stability. Multi-phase faults tend to be more severe and persisting than faults involving only one phase and ground, hence the necessity for various schemes of selective high-speed reclosing. In one such scheme, for example, all reclosing is blocked following indication of a 3-phase fault. A further development in this area is the single pole tripping and reclosing mentioned briefly above. Reclosing control is commonly included in the logic associated with solid-state relays, offering the maximum versatility.

The relays and schemes developed and furnished to date by industry are adequate. However, as systems become more interdependent and fault sources increase in number and magnitude, greater speed and dependability will be required of protective equipment. The existing "building block" approach to relay schemes will have to be expanded to give maximum reliability along with necessary flexibility.

3.5.4 Metering and Data Recording

High-voltage metering is used for revenue metering, interchange accounting, system operation, and control. The data obtained may be classified according to (1) short duration events, (2) continuous data requirements, (3) methods of retention and utilization, and (4) whether it is remote or local information.

A record of short duration events is required to analyze system disturbances and abnormal system operation. Fault recorders, sequence recorders, fault locators, and such other items as surge level recorders are in this category. Ten-cycle prefault recorders are now available which use rate of change of current or voltage relays for initiation. Solid-state alphanumeric-type sequence recorders are in use which print out a sequential log of events such as relay targets and other station alarms and

have memories capable of accepting 60 events in sequence with a two-millisecond discrimination. Surge level recorders are available which record the discharge frequency and level for use in future equipment design.

Records are retained for two principal reasons: (1) system disturbance analysis and (2) as a source of information for system planning or design. The physical problem of storing large volumes of recordings which are seldom referred to has discouraged the old practice of amassing large amounts of normal system data. Recordings used for revenue or interchange accounts must, of necessity, be stored as required.

The trend is definitely toward less local recording and more recording of remote data either by continuous or on-call supervisory with selective telemetering. There will still be local indicating instruments for some time, but with a minimum of recording except for maximum and minimum values of various parameters, fault recorders, and some power plant recordings. Frequent telemetering of interchange quantities is required for area control and is expected to continue. There is a trend toward punched paper and magnetic tape recorders for both revenue and sequence recorders. Also, there is the practice of using television systems for observation of local indicating instruments from a central control point or to display digital information as generated by a digital computer.

Revenue metering at EHV with progressively higher current and potential transformer ratios is suffering progressively poorer resolution. The 0.3% accuracy of instrument transformers now offered is marginal for most EHV installations. Better revenue meters are also needed to measure true rms power from nonsinusoidal currents and voltages.

3.6 Esthetics

3.6.1 Introduction

Expanding power systems to meet the burgeoning electric power appetite in the United States (expected to increase sevenfold by the year 2000) will require more than merely increasing electrical facilities. Because of emerging sociological factors of affluence, leisure, and personal mobility, coupled with the population explosion and land crowding, people are becoming more concerned for their physical and visual environment. Consequently, electric utilities must expand by providing more pleasing (and more costly) facilities and yet retain their enviable record of economical and reliable service.

This discussion of esthetics primarily concerns transmission substations, which function as system switching and voltage transformation centers, generally at voltages above 69 kV. Functionally, substations satisfy electrical system operational and capacity requirements with designs which provide service reliability, ease and safety of operation and maintenance, and reasonable security. Esthetically, however, a substation is a collection of varied shapes, multicolored equipment, and structures highly identifiable with the utility industry and often unrelated to or clashing with its immediate surroundings.

3.6.2 The Substation Esthetics Problem

The difficulty of improving substation esthetics depends primarily on the number of connecting transmission line circuits, their voltage magnitudes and voltage varieties, and, to a lesser degree, on the capacity of the lines and voltage transformations. The primary factors influence substation height and area whereas capacity factors generally dictate equipment size, the amount of peripheral equipment, and area congestion.

Substations with voltages of 69 kV, 115 kV, and perhaps as high as 230 kV are amenable to extensive concealment and camouflaging techniques such as used for distribution substations. Louvered metal or plastic panels attached to substation structures have effectively reduced visual discontinuities and provided form. However, such techniques are likely to become more difficult and costly to apply at higher voltages. Although walls and screens appear impractical for tall and expansive transmission substations, appropriate fences or low walls may be used quite effectively to screen groundline views and provide required security.

With transmission voltages today as high as 765 kV, and perhaps increasing to 1000–1500 kV in the future, substations have physical parameters which have become most difficult, if not impossible to hide or camouflage. It is not only the substations but also the converging overhead transmission lines which defy attempts for visual subduance and present the most difficult esthetic problem.

The practical avenues to improve appearances of most transmission substations are through judicious site selection, improved structural designs, materials and shapes, the appropriate use of colors, landscaping, and possibly some fenceline screening. An orderly arrangement of the connecting lines is

highly important in making the total appearance more acceptable.

3.6.3 Site Selection

Site selection is of prime importance consistent with the objective to provide facilities esthetically harmonious with their area location. Reducing intrusion on personal and public environment increases the facility's acceptance probability. For example, a substation in an industrial or remote rural area will be more acceptable than in a commercial, residential, or recreational area. Sites with foreground and background trees, as well as differences in terrain, can also be used advantageously to attain direct-view screening or minimize the harsh see-through appearance.

3.6.4 Substation Profile

Although economy and reduced land requirements can be derived by vertical levels of buses and line connections, the resultant heights and congestion are usually esthetically detrimental. Low profile or low silhouette substations require more real estate but are considered less obtrusive. The use of rigid buses can be helpful in achieving lower profile for open-air insulated designs. The use of gas-insulated buses and equipment could effect dramatic improvement in profile and other esthetic treatment but at a substantial cost increase.

Typically, substation structures employ latticed columns and beams to economically achieve strength. Unfortunately, their multitude of intersecting braces conveys harsh, visual appearances portraying clutter and busyness. Simplified, less cluttered, and more graceful installations usually result from the substitution of rigid structural shapes such as steel or aluminum "H" sections, tubing, fabricated tapered polyhedron shapes, or prestressed concrete. Uniformity of structures within a substation also is highly important to esthetics.

3.6.5 Color Schemes

Carefully selected color schemes can be quite effective. Conservative, blending colors tend to make the substation less obvious, whereas bold, vivid hues provide accent to dramatize its function. Local environments dictate their application. Painting of metallic components, of course, makes almost any color scheme possible; however, the natural metallic gray of galvanized steel or aluminum and the reddish brown of weathered, corrosion-resistant steel can sometimes be incorporated advantageously. Porcelain elements, which traditionally have been brown, are now also generally available in sky-blue gray, which is considered effective for blending insulator elements against the sky or light backgrounds.

3.6.6 Landscaping

Landscaping often softens the starkness of a substation. Grass, trees, and shrubs, combined with ground contours, retaining walls, and driveways, can derive pleasing improvement. In addition, lighting may enhance a substation's nighttime appearance and serve both decorative and security purposes.

3.6.7 Conclusions

Applied esthetic improvement concepts, with the possible exception of site selection and low profile designs (which require more real estate), increase a substation's installed costs substantially. Additionally, landscaping requiring routine care and maintenance and color effects needing occasional repainting can be costly. Careful selection of any one or several of the various esthetic concepts, and in varying degrees, is required to achieve the optimum transmission substation appearance improvements at reasonable expense.

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CHAPTER 4. AC TRANSMISSION SYSTEM OVERVOLTAGES

4.1 Steady-State Overvoltage Phenomena

4.1.1 Steady-State Power Frequency Overvoltages

When long transmission lines are energized from only one end with the other end open-circuited or connected only to a transformer, serious overvoltages on the line can result from the action of line-charging current flowing through the series inductance of the line. Such a system is shown in Figure 4.1. Shunt reactors may be used to compensate for line capacitance and thus reduce overvoltages but complete compensation is very seldom used.

If the transformers supplying the sending end of the open-ended line operate at voltages above the knee of their magnetization curves, harmonics (Figure 4.2) are generated which can result in further increases of steady-state overvoltage magnitudes.[1] The magnitude of these overvoltages depends on several system parameters, which include transformer leakage reactance and saturation characteristics, amount of shunt reactor compensation and reactor saturation characteristics, reactance of the underlying electrical network (X_e in Figure 4.1), line length, and operating voltage levels.

4.1.2 Load Rejection Overvoltages

Steady-state overvoltages can be caused by load-rejection conditions which arise when the only transmission line power outlet from a loaded generator is open-circuited at the end remote from the generator. Resulting steady-state overvoltages may be particularly severe because of the superimposed effect of generator overspeed and the possibility of self-excitation of the generator.

4.1.3 Nonlinear Voltage Oscillations

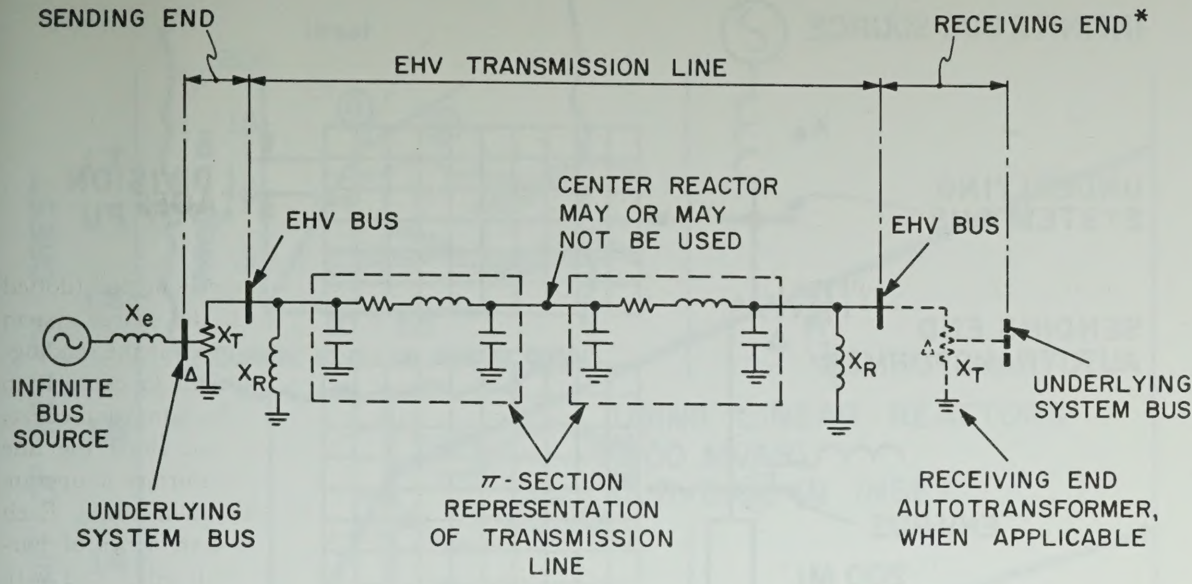
Another condition that can result in steady-state overvoltages occurs when a transmission line is open-circuited at the low-voltage terminals of a step-down transformer at the receiving end (dotted connections in Figure 4.1). If the source system reactance is high, the voltage level at the sending-end transformer may be sufficient to cause it to operate at or over the knee of its saturation curve, while the additional voltage rise along the line will cause the receiving-end transformer to operate at a higher point on its saturation curve. Each transformer will generate its own series of harmonics which interact with each other and with line and system resonances. The fundamental-frequency wave in the steady state exhibits modulation by harmonics, subharmonics, and aperiodic waves. These nonlinear oscillations (sometimes called ferroresonance) may result in very high overvoltages in the steady state at both ends of the line. Figure 4.3 shows oscillograms of such nonlinear voltage oscillations. Nonlinear oscillations can also occur when there is a single transformer at either the sending or receiving end where the oscillations are a result of the interaction between the harmonics generated by the transformer and the resonances of the line and system reactance.

The system parameters that affect the phenomenon of nonlinear oscillations include those mentioned in section 4.1.1 as determining the magnitude of overvoltages but also include the magnitude of source voltage, the resonances of the system, and the amount of load connected to the system at the sending end. These oscillations are largely dependent on the variation of transformer reactances with voltage, and the overvoltages they produce are very difficult to predict with accuracy, even using models to represent the system components.

4.1.4 Effects on Equipment

Thermal limits normally determine the ability of transformers and reactors to withstand steady-state overvoltages because of increased core losses when they are overexcited. Lightning arresters and circuit breakers also are affected by steady-state overvoltages. Figure 4.4 shows overvoltage capability curves for transformers, shunt reactors, and lightning arresters. The transformer overvoltage

See footnote References, end of Chapter.



*OPEN AT EITHER EHV BUS OR UNDERLYING SYSTEM BUS

X_e = SYSTEM EQUIVALENT REACTANCE OF UNDERLYING SYSTEM

X_T = AUTOTRANSFORMER (OR TRANSFORMER, IF USED) LEAKAGE REACTANCE

X_R = LEAKAGE PLUS MAGNETIZING REACTANCE OF SHUNT COMPENSATING REACTOR

Figure 4.1.—Open-Ended EHV Line Connected to an Underlying System.

capability curve has been previously published.[2] The curves for shunt reactors and lightning arresters are intended to indicate capabilities that were found to be desirable, in some instances, from a system performance standpoint. It is important to study the magnitude and time duration of steady-state overvoltages in the early stages of design of a new EHV line or network so that the final design will result in system performance compatible with equipment capabilities.

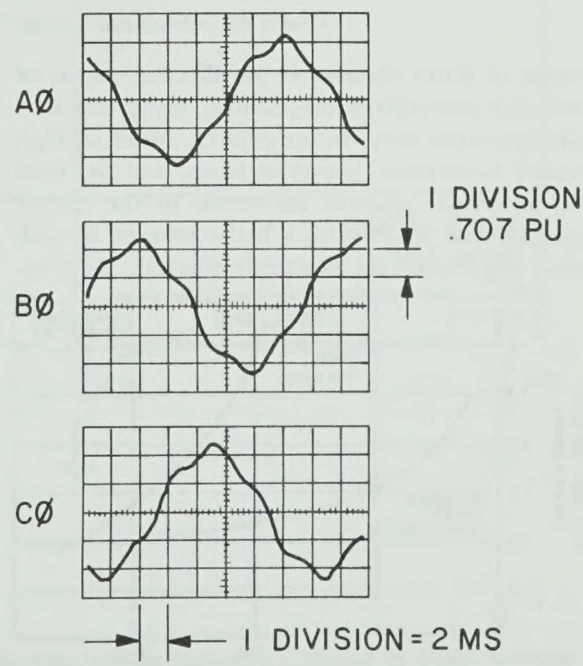


Figure 4.2.—Voltages at Open-Ended EHV Line Showing Harmonic Distortion Generated by Overexcited Sending-End Transformer.

4.1.5 Control of Steady-State Overvoltages

It is necessary to control the magnitudes of steady-state overvoltages on a given system so that they will be compatible with equipment overvoltage capability. Of the previously listed system parameters which determine the magnitude of overvoltages, the rating and characteristics of shunt reactors are most readily and economically varied to provide such control. While an increase in MVA

See footnote References, end of Chapter.

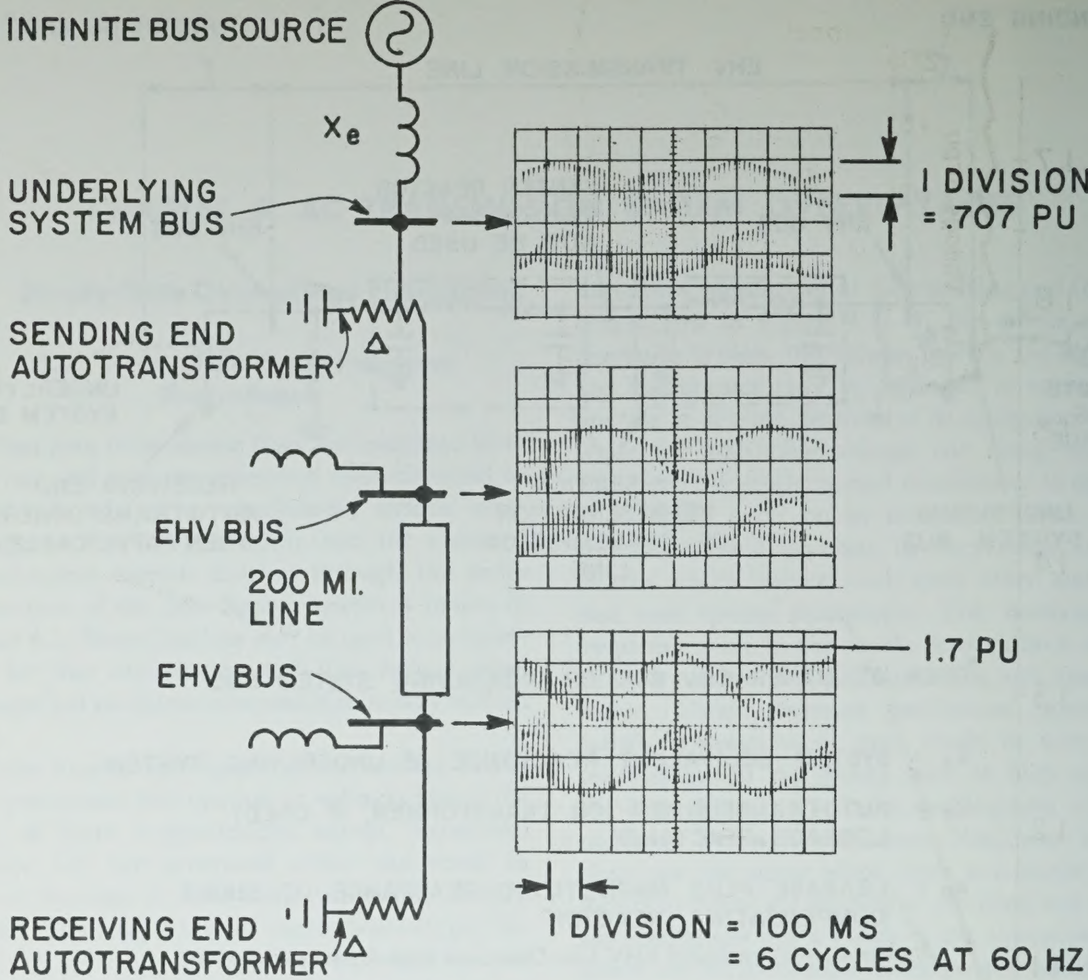


FIGURE 4.3.—Nonlinear Voltage Oscillations on Buses of Line Shown.

rating of shunt reactors is an effective means of reducing overvoltage magnitudes, using this as a sole approach may, in some cases, result in high capital investment, increased losses, and the need for additional reactive correction in the underlying system. At present, a better solution in such cases may be to use nonlinear reactors. Such reactors have saturation curves with a well-defined knee, a slope in the saturated region that is substantially lower than in the unsaturated region,[3] and overvoltage capability to operate above the knee of their saturation curves for many minutes without overheating. These reactors not only provide the minimum compensation required to assure acceptable voltages under normal operating conditions but also provide increased compensation under open-ended line conditions. Figure 4.5 compares overvoltage magnitudes using reactors of the same rating but with linear and nonlinear characteristics.

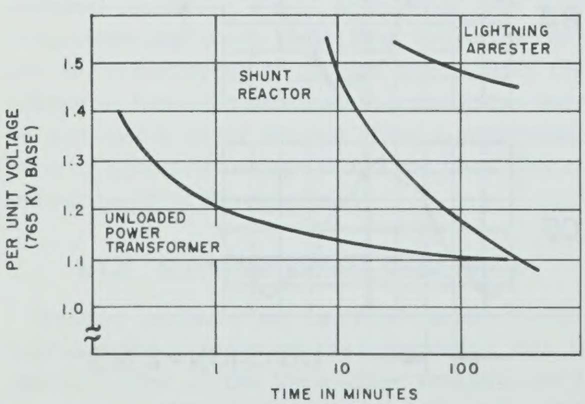


FIGURE 4.4.—Typical Time-Overvoltage Curves for 765-kV Equipment.

To prevent occurrence of excessively high steady-state overvoltages for prolonged periods of time, switching arrangements should be avoided, when designing an EHV system, that could result in unusually long lines being energized during contingency conditions. If this cannot be avoided,

See footnote References, end of Chapter.

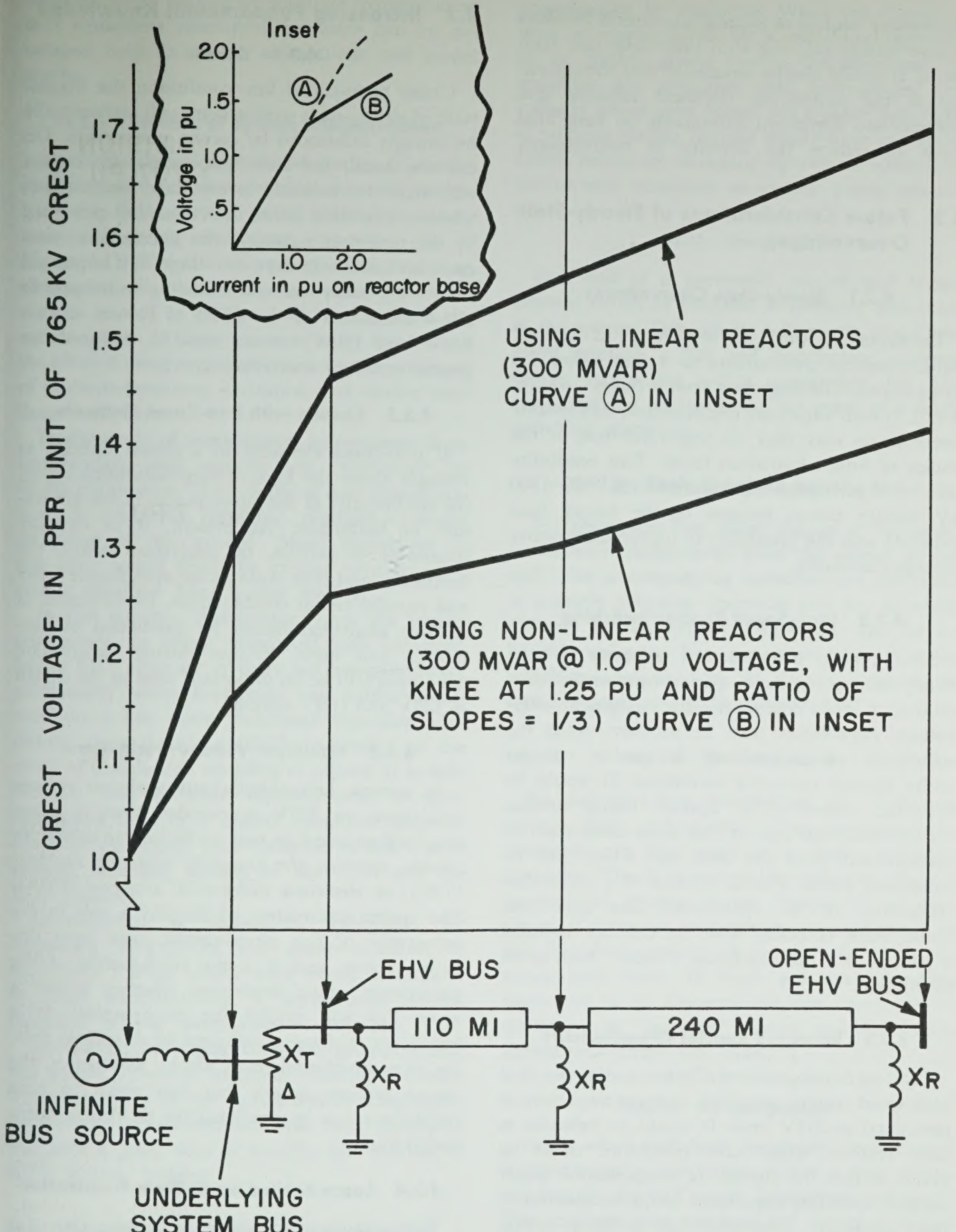


FIGURE 4.5.—Bus-Voltage Profile of Open-Ended EHV Line Showing Voltage Reduction Obtained by Using Nonlinear Shunt Reactors.

supervisory control of appropriate circuit breakers or overvoltage relaying with time delay are both useful. It should also be mentioned that strengthening of the underlying electrical network and intermediate step-down substations on long lines tends to reduce the severity of overvoltages.

4.2 Future Considerations of Steady-State Overvoltages

4.2.1 Steady-State Overvoltages

Development work is underway to control switching-surge overvoltages to values below 1.5 times normal line-to-ground crest voltages[4] (section 4.4.5). If such values are implemented, steady-state overvoltages may play an important role in the choice of future insulation levels. This possibility will be of particular importance in the 1000–1500 kV voltage classes because of the longer lines expected and the possibility of higher transformer leakage reactances.

4.2.2 High-Speed Reactor Switching

Shunt-reactor compensation necessary to hold steady-state overvoltages during open-ended conditions at levels consistent with equipment overvoltage capabilities may be excessive from the standpoint of maintaining acceptable voltages under normal operating conditions. It would be desirable, therefore, to operate under normal system conditions with at least some shunt reactors disconnected from the lines but which can be connected within a small fraction of a cycle after occurrence of an open-ended line condition. Some work is being done to develop switches capable of accomplishing such high-speed connection.[5]

4.2.3 Improved Reactor Characteristics

Pending development of effective and economical high-speed reactor switching, reactors must remain connected to EHV lines. It would be valuable to have reactors whose core reluctance could be varied so that the amount of compensation under normal operating conditions could be controlled. Such capability, combined with nonlinear operation during overvoltages, would provide greater flexibility in meeting the voltage requirements of both normal and open-ended operating conditions.

See footnote References, end of Chapter.

4.3 Increasing Fundamental Knowledge

4.3.1 Corona

Under open-ended line conditions, the magnitude of steady-state overvoltages will undoubtedly be strongly influenced by corona phenomena. On the one hand, the losses associated with corona will tend to decrease overvoltage magnitudes, while on the other hand, the harmonics generated by the nonlinear nature of the phenomena may cause an increase in the overvoltage. It is important to develop analytical and modeling techniques to allow assessment of the effect of corona so that EHV and UHV systems can be designed for greater economy and reliability.

4.3.2 Circuits with Iron-Cored Elements

If iron-cored elements in a circuit operate at voltages above the knee of their saturation curve, the nonlinearity of the curve results in the generation of harmonics. At present, it is virtually impossible to predict, by analytical means, the harmonics and crest voltages for even simple series and parallel circuit combinations. Development of suitable analytical means for prediction of harmonics and crest voltages during steady-state conditions will be an important asset in the design of EHV and UHV systems.

4.3.3 Nonlinear Voltage Oscillations

At present, knowledge about nonlinear voltage oscillations on EHV open-ended lines is either empirical or based on tests performed on miniature models such as the transient network analyzer (TNA) or electronic differential analyzer (EDA). The system parameters which play a role in the occurrence of this phenomenon have been discussed above, and it is the combination of the parameters which determines whether or not a given line will exhibit the phenomenon. It is important to develop sufficient knowledge so that, for given combinations of system parameters, the source voltage ranges that can result in such oscillations can be predicted for particular open-ended lines.

4.3.4 Loads Excited by Multiple Frequencies

When transformers operate at voltages above the knee of their saturation curves during open-ended line conditions, harmonics are generated which are applied to loads simultaneously with the fundamental frequency. It is important to increase our knowledge of how loads (motors, transformers,

etc.) act when excited by multiple frequencies so that equivalent reactances for loads can be developed both for use in calculations and model studies.

4.3.5 Validity of System Representation

In the analytical and model studies of steady-state overvoltages, the electrical network underlying the EHV network being studied is usually represented by an equivalent reactance (X_e in Figure 4.1). Use of such an equivalent reactance eliminates all the numerous parallel-resonant circuits as well as all the loads that exist in the actual system. It is important to know more about the effect of using such a reactance under conditions of multiple-frequency excitation and during nonlinear oscillations.

In the study of overvoltages, transmission lines, transformers, and reactors are represented by 60-Hz parameters. The validity of such representation in problems involving multiple-frequency excitation is not proved. More knowledge in this area would result in greater confidence in results obtained from model studies.

In this country, transmission lines are usually represented as being transposed and balanced. Many EHV lines are actually not transposed and, particularly when harmonics and subharmonics exist on a line under nonlinear operating conditions, there is little available knowledge on the effect of unbalanced coupling of phases. It is only recently that accurate representation of non-transposed lines in a digital computer program has been developed. More progress in this area is needed, including models for the TNA and the EDA studies.

Development of convenient techniques for measuring magnitudes and phase relations of harmonics during model tests would contribute to fuller understanding of transmission system behavior during overvoltage conditions.

Development of digital computer programs that will permit the use of nonlinear elements and non-transposed lines for the calculation of steady-state overvoltages is an important task. Such programs will save a good deal of time in the analysis of EHV system designs.

4.4 Switching Operation Overvoltages

4.4.1 Switching Operations Resulting in Surges

Whenever an electric circuit is forced from one steady state to another, the change of state is accompanied by transients. When the change of state is accomplished by a switching operation on an electric power system, the accompanying transients are associated with overvoltages, i.e., voltages whose crest values are greater than those of voltages during normal steady-state operation. Listed below are switching operations which give rise to such transients on electric power systems.

4.4.1.1 Energization

One end of a previously unenergized system element or set of elements is suddenly connected to the system. This can be a line with or without shunt reactors, a line and transformer, a transformer and a line and a transformer, etc. The accompanying transients are the result of a single switching operation.

4.4.1.2 Single-Ended Tripping of a Line

A transmission line, either loaded or unloaded, is suddenly disconnected from the system at one end. The accompanying transients are the result of a single switching operation and are generally different for an initially loaded line and for an initially unloaded line. In either case, after the switching operation, the line is connected to the system at only one end and unloaded.

4.4.1.3 De-energization

An unloaded line, transformer, etc. is disconnected from the system. The accompanying transients are the result of a single switching operation. The disconnected line will have different amounts of electric charge "trapped" on each phase. If there are no shunt reactors connected to the line, the amount of charge will gradually decay with time. If there are shunt reactors connected to the disconnected line, there will be oscillations of "trapped" charge, and these oscillations will decay with time.

4.4.1.4 Re-energization

A line which had been previously de-energized is reconnected to the system within a time of approximately one-half second (high-speed reclosing). The accompanying transients are the result of two switching operations, one at each end of the line, which are almost simultaneous since they are usually performed within a cycle (16.7 msec) of each other. The transients accompanying re-energization are strongly affected by the residual

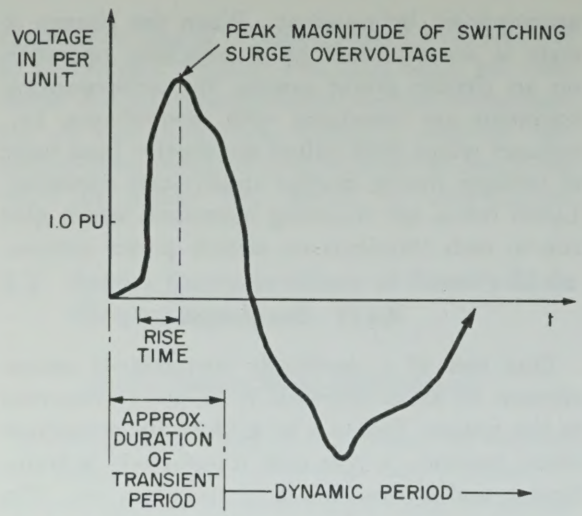


FIGURE 4.6.—Switching-Surge Period Wave Illustrating Meaning of Terms.

"trapped" electric charge on each phase of the line.

4.4.2 Description of Overvoltage Periods Due to Switching Operations

Experience in analyzing transients associated with switching operations has shown the desirability of recognizing three distinct periods of time.[3]

4.4.2.1 *Switching-Surge or Transient Period*

This interval starts, for an energization or re-energization operation, with the closing of the first breaker pole and is characterized by traveling wave effects, which take several milliseconds depending on the length of the transmission line. For a de-energizing or tripping operation, the period starts with the opening of the first breaker pole and, again, ends with the vanishing of traveling wave effects. During this period, system elements are represented by their surge impedances for analytical purposes.

The overvoltages associated with the transients during this period can often be described by assuming an exponential waveshape whose peak magnitude and rise time can then be specified,[3] as illustrated in Figure 4.6.

4.4.2.2 *Dynamic Period*

This interval starts with the traveling wave effects and ends with the beginning of the new steady state which was the goal of the switching operation. It is characterized by slowly changing wave forms, distorted from the sinusoidal, which are nearly periodic and are contained in an envelope which varies aperiodically with time. This period can last for as long as one second. The transients of this period result in repeated overvoltages which are, in general, smaller in magnitude, on a given circuit, than the overvoltage associated with the transient period. Figure 4.7 illustrates overvoltages during the dynamic period.

4.4.2.3 *Steady-State Period*

During this period, voltages are periodic but may be distorted. Overvoltages associated with this period are treated in sections 4.1 and 4.2 of this chapter.

4.4.3 System Parameters and Other Factors Affecting Overvoltages

The magnitude of overvoltages associated with the transients of the switching surge and dynamic periods are determined by various system parameters and equipment characteristics. Among the more important of these are line length, strength of the underlying system, state of the circuit prior to switching, shunt reactive compensation, transformer inrush and saturation characteristics, the time (or angle) on the system voltage wave at which switching takes place, the use of resistors during switching operations and the characteristics of lightning arresters.

In general, if no attempt is made to limit switching-surge overvoltages, the most severe overvoltages result from re-energization operations, followed, in the order of reduced severity, by those resulting from energization and single-ended tripping of a loaded line and de-energization.

4.4.4 Effects on Equipment

The ability of lines and stations to withstand switching-surge (transient-period) overvoltages is determined by the system insulation level and the performance of lightning arresters. The switching-surge overvoltage resulting from a switching operation is strongly influenced by the point in time at which electrical contact is made or is broken on the first phase and the relative time intervals to the making or breaking of contacts on the remaining two phases. Since these times are random, (work is currently underway to develop commercial means of controlling the timing), the magnitudes of the resulting overvoltages are also random and the probability of occurrence of overvoltages of different magnitudes is evaluated

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See footnote References, end of Chapter.

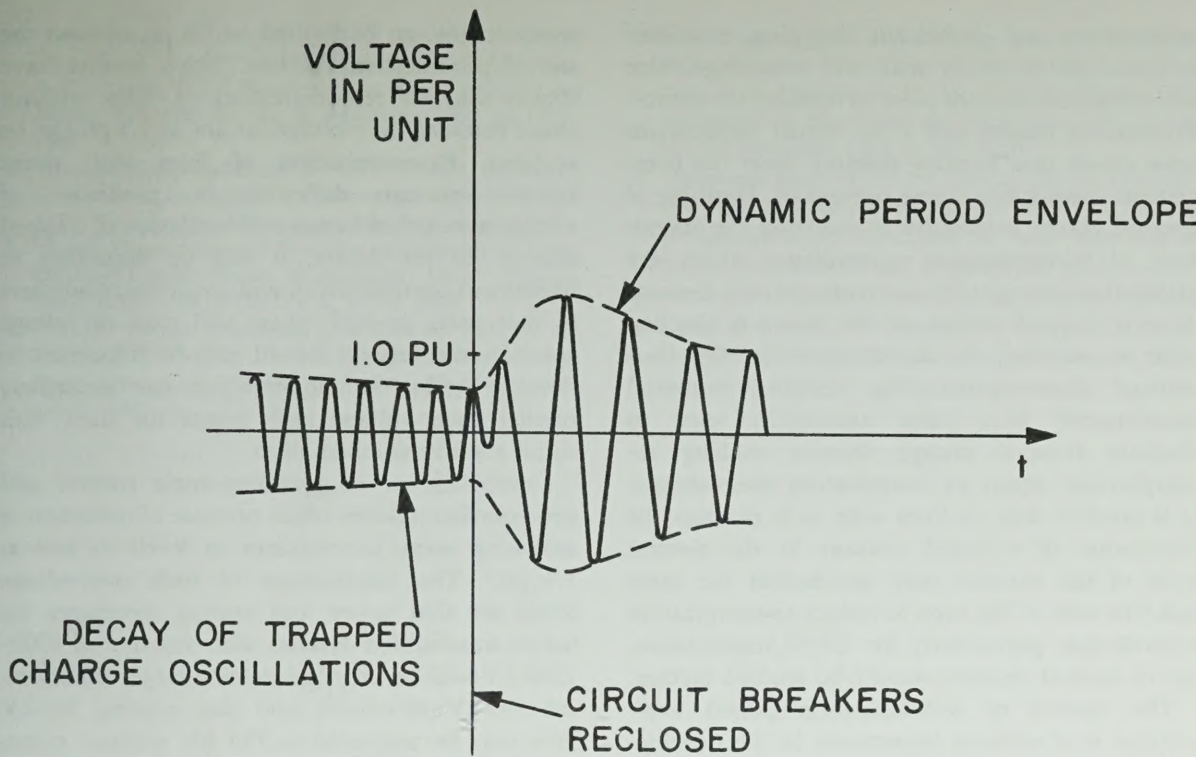

FIGURE 4.7.—Dynamic-Period Wave Illustrating Meaning of Terms.

statistically. The insulation level chosen for lines and stations is based on statistical evaluations of insulation strength taken in conjunction with the probability of various switching-surge overvoltage magnitudes.

The ability of specific equipment, such as transformers and shunt reactors, to withstand switching-surge overvoltages is determined by the insulation strength of the equipment and the ability of lightning arresters to limit the magnitude of these overvoltages to values compatible with equipment insulation. Lightning arresters must also protect equipment from lightning-surge overvoltages which generally have much shorter rise time (several microseconds) than do switching-surge overvoltages (several hundred microseconds). In general, equipment insulation design has been based on ability to withstand lightning-surge overvoltages for transmission voltages below 345 kV, while, for transmission voltages of 345 kV and above, ability to withstand switching-surge overvoltages has been the guiding criterion.

The severity of the duty imposed on equipment by dynamic-period overvoltages is due both to their magnitude and to their repetitive nature. Lightning arresters are particularly sensitive to the repetitive nature of these overvoltages.[6] Dynamic-period overvoltage magnitudes are a random phenomenon for the same reasons as are switching-surge overvoltage magnitudes. They have not, however, been studied on a statistical basis to date, and their effect is evaluated by using the maximum of the enclosing envelope.[3]

4.4.5 Control of Switching-Surge Period Overvoltage—Present and Future

To date, the means that have been used to directly control the maximum switching-surge overvoltage magnitudes on a given system include lightning arresters, switching-device resistors, and the discharge of trapped energy. Modern arresters are designed to hold switching-surge overvoltages below specified values by discharging energy associated with the overvoltage peaks. Switching-device resistors can be applied during closing and opening operations of circuit breakers. On closing, i.e., during energization and re-energization, a resistor is connected in parallel with the switching-device gap for several milliseconds prior to the closing of the switching-device.[7] Appropriate choice of resistor size and length of preinsertion time can limit re-energization overvoltages to 2.1 pu or lower. On opening, i.e., during de-

See footnote References, end of Chapter.

See footnote References, end of Chapter.

energization and loaded-line dropping, a resistor is connected in series with the switching-device for several milliseconds prior to opening the device. Preliminary studies and a few actual applications have shown that opening resistors lower the overvoltages arising from these operations. Draining of trapped energy is effective in reducing the magnitude of re-energization overvoltages which are higher than energization overvoltages only because there is trapped charge on the phases of the line prior to reclosing the switching-device. On lines without shunt-compensating reactors, potential transformers[9] have been successfully used to dissipate trapped charge thereby making re-energization equal to energization overvoltages. It is possible that on lines with such reactors the installation of switched resistors in the neutral leads of the reactors may accomplish the same task.[3] In view of the need to reduce re-energization overvoltages, particularly for UHV transmission, use of neutral resistors should be studied further.

The control of switching-surge period overvoltages is of extreme importance in the development of future transmission systems with voltages above 765 kV. It was mentioned above that the ability of lines and stations to withstand switching-device overvoltages is determined by system insulation level. The desired system insulation level is achieved by obtaining clearances between phase and ground and between phases that are appropriate for the available porcelain-and-air insulation systems. The clearances are among the most important factors in determining the overall dimensions of transmission and switchyard structures. To keep these to sizes that are acceptable from the point of view of economics and esthetics, it is of crucial importance to substantially reduce switching-surge overvoltages below the value of 2.1 pu obtainable today using one-step pre-insertion resistors. This can be accomplished by equipment improvements and by increasing fundamental knowledge.

Studies have shown that the insertion of a second step of resistance prior to closure of the main breaker contacts can further reduce switching-surge period overvoltages.[4] In the future, it will be important to implement two-step, and possibly multi-step, resistor insertion in circuit breakers.

If the circuit-breaker contacts are closed when the voltage across them is zero, significant reduction in switching-surge overvoltages can be achieved. Studies have shown that for dead-line energization, overvoltages can be limited to 1.8 pu without the use of pre-insertion resistors. Other studies have shown that for re-energization of lines without shunt reactors, overvoltages as low as 1.3 pu can be realized. Re-energization of lines with shunt reactors presents difficulties in prediction of voltage zero points because of oscillation of trapped charge. In the future, it will be important to implement controls which will synchronize breakers so that poles on each phase will close at voltage zero. In this regard, it will also be important to develop sensing techniques which can accurately predict such voltage zero points for lines with shunt reactive compensation.

Combined use of switching-angle control and pre-insertion resistors offers promise of reduction of switching surge overvoltages to levels as low as 1.4 pu.[9] The implications of such overvoltage levels are that tower and station structures for future transmission systems with voltages of 1000–1500 kV will be only moderately larger than present 765-kV structures, and that existing 345-kV lines may be upgraded to 765 kV without extensive rebuilding. In view of the growing scarcity of rights-of-way and public reluctance to accept large transmission structures, the importance of these reductions in switching-surge overvoltage cannot be overemphasized.

4.4.6 Control of Dynamic-Period Overvoltage—Present and Future

To date, control of dynamic-period overvoltages has involved the design of satisfactory lightning arresters to tolerate the repetitive overvoltage peaks which are characteristic of the dynamic period. While dynamic overvoltages have not been studied to the same extent as switching-surge overvoltages, indications are that use of pre-insertion resistors is ineffective in their control.

The two most promising means of reducing the magnitudes of dynamic overvoltages appear to be the synchronized breaker-pole closing, which is effective both in dead-line energization and in re-energization, and the draining of trapped charge, which is effective in re-energization.

See footnote References, end of Chapter.

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CHAPTER 5. SYSTEM STABILITY

5.1 Introduction

Power system stability is one of the fundamental considerations in the design and operation of modern power systems. Any well-conceived extension of the generation and transmission facilities to meet future system load requirements must include a proper evaluation of system stability. Furthermore, stability considerations play a vital role in appraising the reliability of operation of a power system, particularly when abnormal conditions cause the mode of operation to move toward the limits which are inherent in the design.

The problem of power system stability and its importance in system performance considerations have been recognized since alternating-current generation and transmission systems came into existence. The basic theory of system stability and the formulation of effective, practical means to deal with its influence on system performance have been an integral part of the progress of power system technology. The principal challenge today and tomorrow lies in the sound application of the basic theory and in the development of improved analytical techniques for a wider range of situations arising from the continued growth of electric power systems.

The role of system stability considerations in the achievement of system reliability has been discussed elsewhere.[1] This chapter will (1) briefly discuss the well-known fundamental concepts of power system stability, (2) note those current design trends, particularly in transmission network design, which have a direct bearing on stability considerations, and (3) cite a number of factors which may be important in meeting the challenge of the future to provide for reliable system performance.

5.2 Stability Considerations

Stability may be defined as that attribute of the power system, or part of the system, which enables it to develop restoring forces, between the elements thereof, equal to or greater than the disturbing forces so as to restore a state of equilibrium.[2]

System stability is assessed from a knowledge of the system dynamic behavior following a disturbance. The dynamic response of a power system to a disturbance is determined by use of suitable mathematical or analog models to simulate the behavior of system elements.[3,4] The method of simulation and the degree of sophistication required in developing the model depend on the nature of the disturbance and the precision required.[5] The solution of the mathematical equations which simulate system behavior is such that, for convenience, stability analysis is classified into two basic categories dependent on whether the disturbance is small or large; these categories are called "steady-state stability" and "transient stability", respectively.

In assessing the stability of a system, the degree of stability is a more useful concept than a simple statement of whether the system is stable or unstable with respect to a given disturbance. Since power systems are inherently nonlinear, the degree of stability cannot be determined explicitly but rather may be inferred through a knowledge of the system behavior following a disturbance for both the expected mode of operation and that mode of operation which results in instability for the same disturbance. In transient stability studies, for example, commonly used indicators of degree of stability are either the expected switching time in relation to the critical switching time under the expected power loading conditions, or the expected power loading in relation to the maximum allowable power loading on the basis of expected switching time.

The principal factors which influence system stability are (1) the nature of the disturbance, characterized by its type, location, and duration, and (2) the nature of the system, including its initial operating state. For example, system dynamic behavior may be fundamentally different, depending on whether the disturbance involves a

See footnote References, end of Chapter.

short-circuit on the system or the loss of generation or of a major load. The location of the disturbance, particularly in relation to the system generators, also has a direct bearing on system behavior. It is the combination of type and location of the disturbance which determines the severity of the resultant dynamic behavior. Consequently, disturbances which are of particular concern are the occurrence of short-circuits near the generating plant or the loss of a major tie line between generation areas or systems. The former raises the question of the stability of the plant relative to the system, while the latter raises the question of inter-area or inter-system stability.[6]

The nature of the system, as previously mentioned, also has a direct influence on system dynamic behavior and includes several facets. The power system is made up of a diverse collection of elements. The arrangement of these elements, their electrical and mechanical characteristics, the presence of automatic control, and the pre-disturbance system state all have an influence on system behavior following a disturbance. Within technical and economic limits, there factors may be taken into account in system design to yield acceptable stability characteristics with respect to a given disturbance.

The presence and characteristics of automatic control schemes may have a significant effect on stability. Automatic control on power systems includes two basic forms: (1) network control, which not only removes the source of a disturbance but also may involve the switching of other elements for improved dynamic performance and (2) generator excitation/prime-mover speed control. The effect of these automatic controls on stability depends on the nature of the disturbance and the response characteristics of the control systems.

During normal system operation, dynamic oscillations may arise which can lead to a potential stability problem. Weak interconnections between large systems are susceptible to this type of dynamic behavior; once these oscillations are excited they may be sustained or increased by negative damping effects produced by machines responding to speed-governor and/or load-frequency control.

5.3 Trends Influencing System Stability

5.3.1 The Trends

The basic assumptions pertaining to adequate system simulation and to the nature of the disturbances used in assessing system stability are closely related to the basic character of the system and to its physical characteristics. As power systems continue to grow, the concepts of stability remain the same but the character of the system and its components is subject to change. Consequently, any trends which indicate changes in those factors which influence stability are of particular interest. The disturbance criteria and the simulation techniques used in determining stability characteristics must be reviewed on a continual basis to insure that they are consistent with these trends.

The most important current trends in power system development that affect stability, and hence system reliability, are (1) increasing extension of EHV transmission networks, (2) changing patterns of generation and transmission, (3) increasing size of generating units, (4) changes in boiler and turbine design, and (5) improved response capabilities of control systems. EHV transmission networks are discussed in section 5.4, while the remaining factors are discussed in the following sections.

5.3.2 Generation and Transmission Patterns

There are presently two general trends which will undoubtedly continue simultaneously. On the one hand there is the advent of nuclear generation, with the possibility of locating the generating stations nearer to the load centers. On the other hand there is the rapidly developing EHV transmission technology which will favor long-distance transmission of economical fossil-fueled and hydro generation. In the latter case, stability considerations play a dominant role and may require special attention.

5.3.3 Increasing Size of Generating Units

The size of generating units is continually increasing to take advantage of the economies of scale inherent in the larger units. The trend in unit size is indicated in Figure 5.1 which shows the maximum rating of 3600 rpm, tandem generators on order over the past thirty years.[7]

The most important consequences of this trend which are related to stability considerations are both electrical and mechanical. The increase in capacity of synchronous generators has been achieved mainly through design of advanced cooling techniques together with advances in materials

See footnote References, end of Chapter.

See footnote References, end of Chapter.

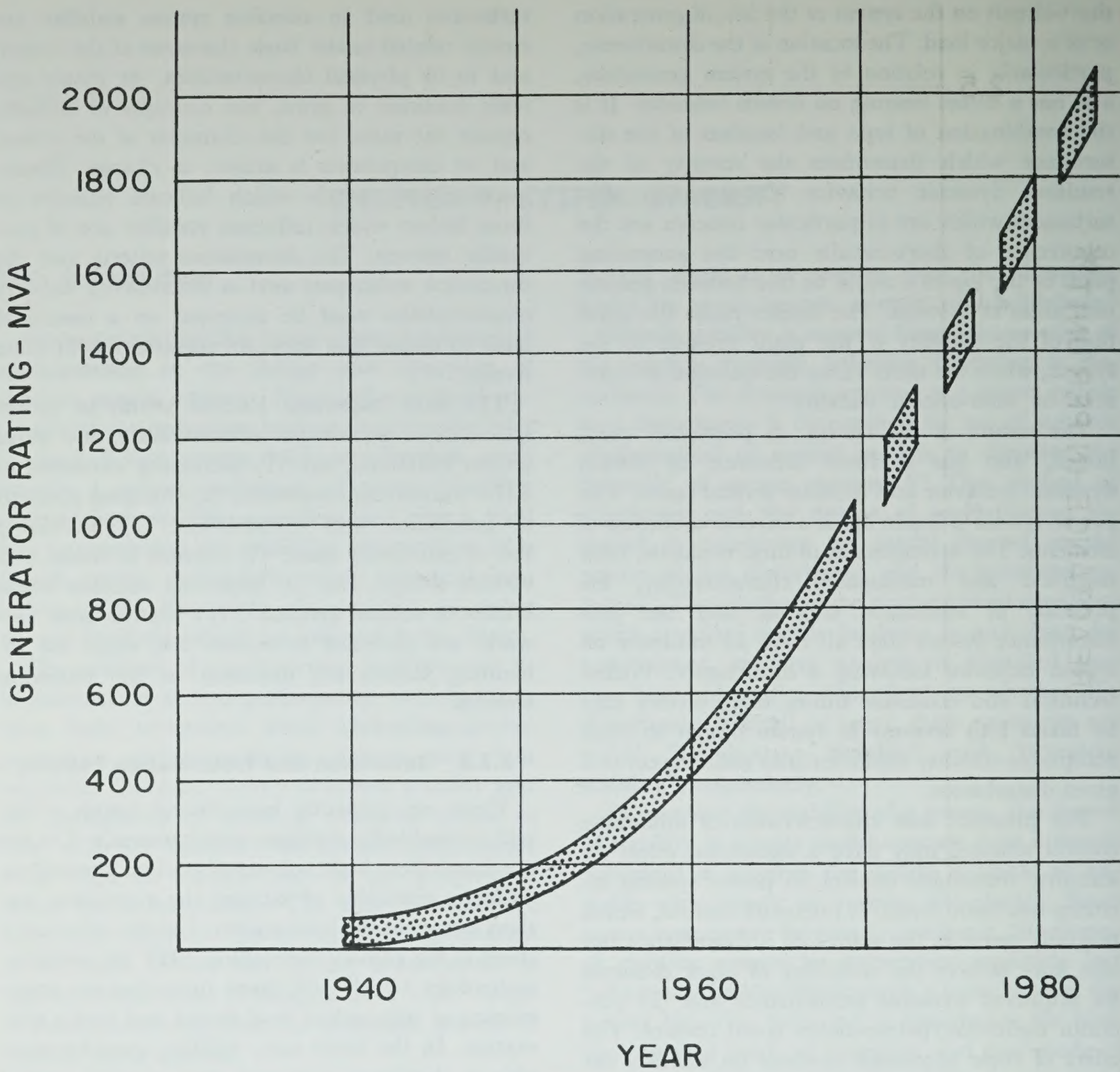

FIGURE 5.1.—Trend in Maximum MVA Rating of 3600 rpm Tandem Generators on Order.

technology yielding a greater capacity for a given physical size. One principal result of these efforts is that the machine reactance has increased as shown in Figure 5.2. The trend toward higher generator reactances is detrimental to stability, i.e., for a given amount of power transmitted from a given generator, the system is less stable both in a steady-state and transient sense as the generator reactance increases. The influence of this factor in determining system stability characteristics takes on increasing importance as the electrical distance between the generator terminal and the system decreases.

Another consequence of design benefits derived principally from advances in the technology of materials is the higher operating steam temperatures and pressures which may be tolerated in conventional fossil-fired units. This leads to a greater power developed for steam turbines of a given size. This fact, together with the increase in the generator capacity in relation to physical size, leads to a tendency for lower inertia constants (stored kinetic energy of the rotating elements in per unit of generator capacity), as illustrated in Figure 5.3. This trend toward lower inertia constants is also detrimental to stability, since generators will accelerate faster when subjected to a given disturbance. The implications of these trends in generator reactance and in inertia constant point to the increased emphasis which must be placed on effective system design to accommodate these higher-reactance, lower-inertia generating units in the future.

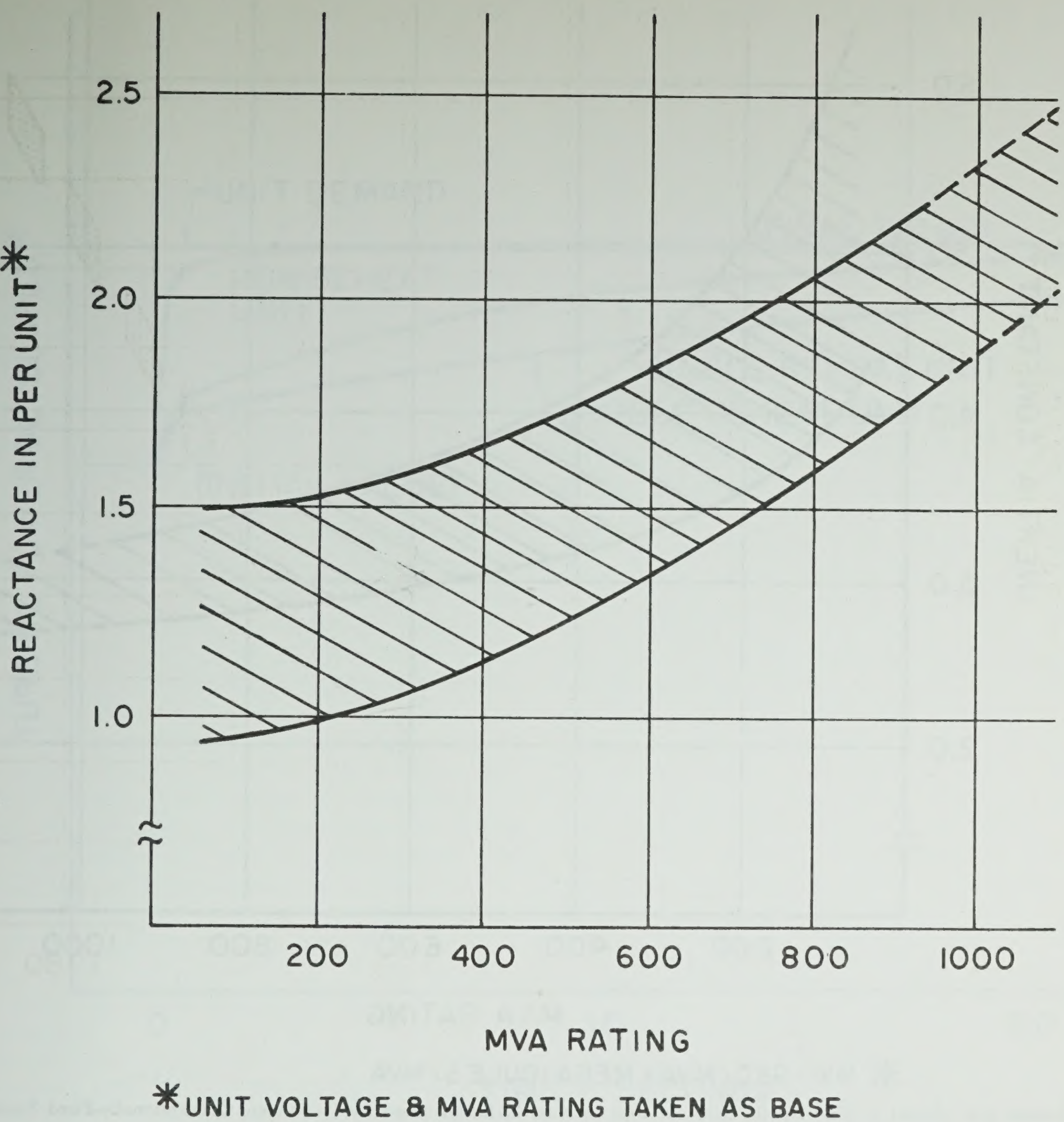

FIGURE 5.2.—Trend in Unit Synchronous Reactance with Increase in Design Capacity (3600 rpm, Conventionally-Fired Steam Units).

5.3.4 Changes in Boiler and Turbine Design

The need for higher capacity steam systems to supply the larger generators has brought about significant changes in design, including basic modifications in the steam generation process itself, principally as a result of advances in metallurgical properties of the materials. This has led to greater energy density in the boiler with associated refinements in the process control. It has also led to the economic justification of one or more reheat cycles to boost the overall steady-state unit efficiency.

The presence of one or more reheat cycles in large units raises the question of the response capability of the unit following system emergencies which require a sudden increase in unit output. Such emergencies may arise from a sudden loss of generation on the system or from a major disturbance which results in a generation-deficient island. If the system has sufficient spinning reserve, the ability of that system to recover depends directly on the response capability of those units carrying the spinning reserve. Figure 5.4 illustrates how typical units with up to two reheat cycles would respond, under ideal conditions, following a sudden increase in unit demand.

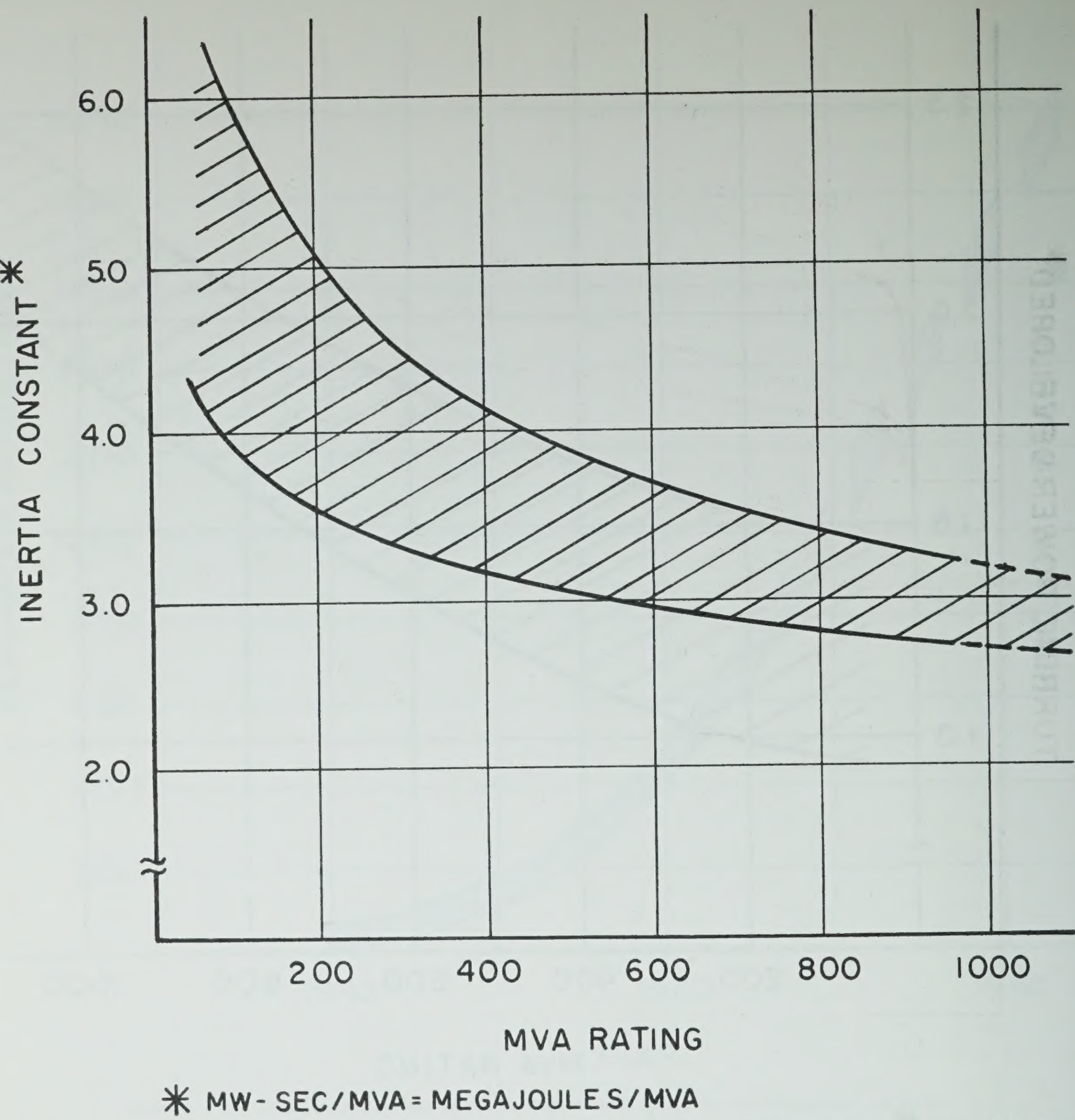

FIGURE 5.3.—Trend in Unit Inertia Constant with Increase in Design Capacity (3600 rpm, Conventionally-Fired Steam Units).

5.3.5 Improved Response of Control Systems

Generator excitation systems have greater capacity with respect to generator size and have faster response. This, and supplemental signals for damping dynamic oscillations, improves the stability of the generating unit relative to the system. Care must be taken to ensure that these new control schemes are applied properly in order to prevent inter-area or inter-system oscillations.

Also, the newer steam generation processes require more sophisticated and sensitive control to maintain desired steam conditions under changing unit demands. These controls must be compatible and coordinated with system controls outside the plant so as not to cause instability problems.

5.4 The Transmission System and Stability

The transmission system is one of the most important factors in achieving a high degree of system reliability. It is the vital link between the generating stations and the load centers, and provides the interconnections with other power systems. It not only provides for energy transportation under normal system operating conditions, but it

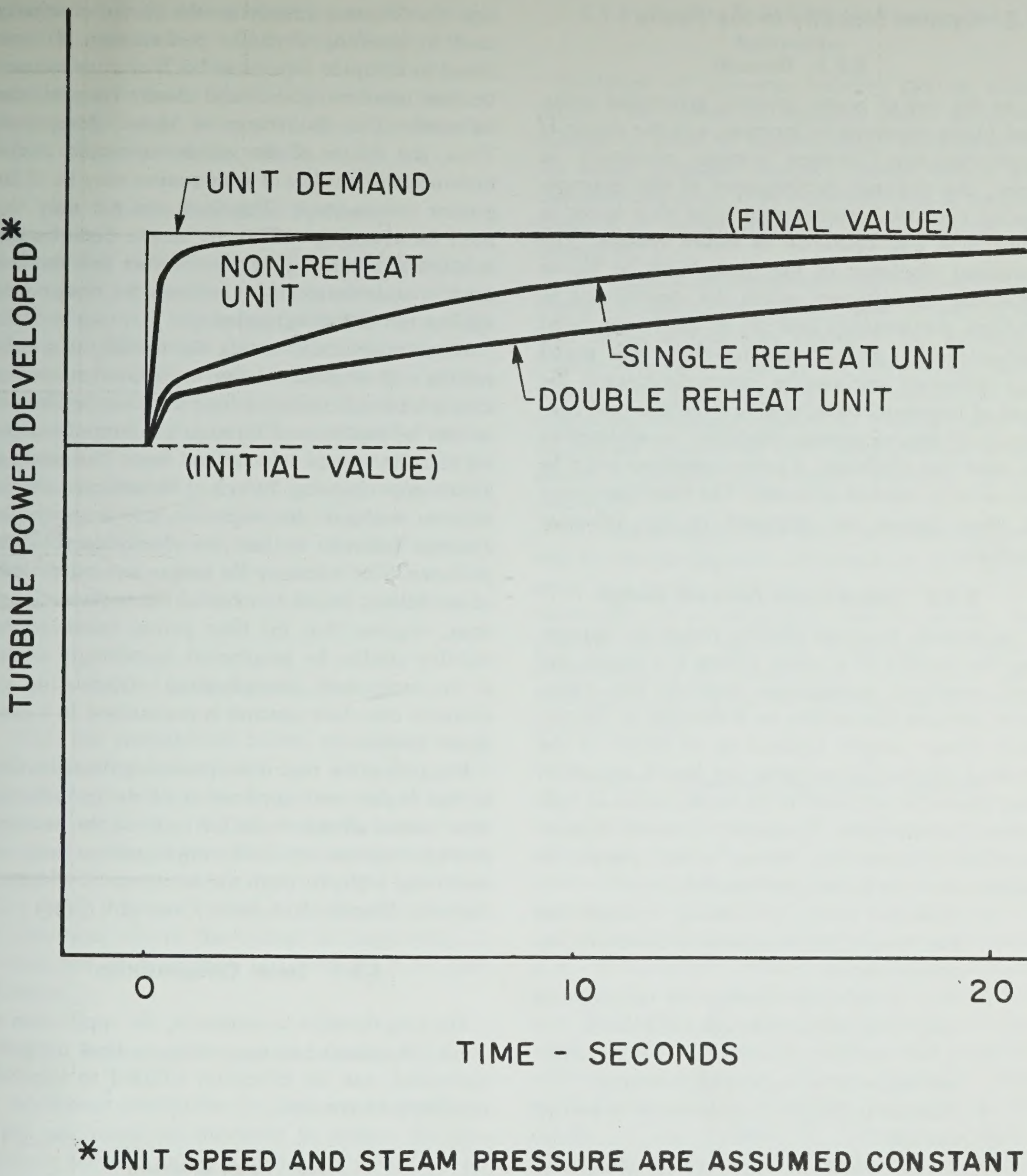

FIGURE 5.4.—Response of Various Type Steam Turbines to a Sudden Change in Unit Demand.

also plays a dominant role in maintaining system stability during emergency conditions due to facility outages or other system disturbances. A necessary condition for reliability of operation, therefore, is the existence of a transmission system with a reserve power-flow margin for the abnormal power swings that are certain to occur.[1] Without such a transmission reserve, system reliability is threatened, and disturbances could cascade into a major power failure.

The current trend is toward the development and extension of EHV transmission networks, both within individual power systems and as a means of interconnecting neighboring power systems. In general, this means that increased emphasis must be placed on the study of inter-area and inter-system dynamic behavior, while at the same time continuing the attention which has been given to the question of stability of the single plant relative to the system.

5.5 System Stability in the Future

5.5.1 General

As the size of power systems, generating units, and plants continues to increase, and the extent of interconnection between systems continues to grow, the dynamic performance of the interconnected network becomes more vital as a factor in the design and operation of future systems. The principal challenge of the future will be (1) to recognize those trends which are detrimental to stability performance and (2) to apply the latest technological developments together with sound and informed engineering judgment toward the goal of improved stability characteristics and consequently greater system reliability. In attempting to meet this challenge, a proper emphasis must be placed on a number of factors. The more important of these factors are discussed in the following sections.

5.5.2 Transmission Network Design

In general, the most effective means for improving the stability of a power system is a strong and well conceived transmission network. The industry's Advisory Committee on Reliability of Electric Bulk Power Supply outlined in its report to the Federal Power Commission the broad principles that should be followed in the sound design of bulk power transmission networks.[1] General recommendations from that report, which pertain to transmission networks, are repeated here.

1. Maintain proper relationship between size and capacity of all system elements, or between systems.
2. Plan for adequate margins of transmission reserve capability through EHV lines.
3. Avoid excessive concentration of transmission capacity on a given right-of-way.
4. Maintain adequate interconnections among systems.
5. Avoid concentration of critical circuits at substation switching facilities.
6. Use relay schemes of least complexity that provide the required protection with the least hazard in the event of faulty operation or testing.
7. Examine proper transmission network contingencies when investigating system performance.

5.5.3 System Dynamic Performance Criteria

In addition to transmission network design considerations, there are overall aspects of system design that depend directly on the choice of criteria used in assessing dynamic performance. It was noted in Chapter 1 (section 1.5.7) that as systems become more integrated and closely coupled, the influence of a disturbance is more widespread. Thus, the failure of the system to sustain a disturbance without loss of synchronism may be of far greater consequence. This indicates not only the need for choosing sufficiently severe disturbances as criteria in making stability studies but also the need to coordinate among systems the choice and application of contingencies.

When analytically testing the stability of a generating unit or plant relative to the system, studies should be made assuming long duration faults such as may be experienced through a failure of switching to isolate the fault in normal time. The need for judiciously choosing extreme disturbance conditions to evaluate the inter-area and inter-system dynamic behavior is therefore of considerable importance. The tendency for longer natural periods of oscillation, found to exist in inter-system situations, requires that the time period examined by stability studies be lengthened accordingly while, at the same time, the precision in simulating all elements and their controls is maintained in a consistent fashion.

Regarding the means for providing coordination in the choice and application of design criteria, such means already exist for most of the country through regional reliability organizations and, on a national scale, through the more recently formed National Electric Reliability Council.[8]

5.5.4 Series Compensation

For long-distance transmission, the application of series impedance compensation, when properly controlled, can be effectively utilized to improve stability performance.

5.5.5 Fault Clearing

A reduction in the switching time required by the relays and circuit breakers to clear a fault is an effective means for improving system stability. The total operating time for breakers (including fault detection and relay time) to clear a fault in primary time may be reduced to 2 to 3 cycles, which is near the minimum that can be obtained. However, backup circuit breaker schemes, set to open adjacent breakers should the normal clearing

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See footnote References, end of Chapter.

scheme fail to operate properly, presently are designed to operate in 8 to 14 cycles. Efforts to reduce the backup time without loss of reliability are especially relevant in view of the current trend to assume a failure of the normal clearing scheme as a part of system stability criteria.

5.5.6 Excitation Systems

Generator excitation control systems may now be designed for very fast response, which can be an effective means of improving the stability of a plant relative to the system. Also, the excitation system can be used to damp system oscillations through the use of properly designed and adjusted supplementary signal inputs which are responsive to the dynamics of these oscillations. Under special circumstances, excitation control systems may actually contribute to the development of system oscillations. In such instances, the use of supplementary signal inputs can again alleviate the situation. This is an area that is in need of further careful study and analysis.

5.5.7 Boiler-Turbine Control

With the complicated boilers now being used, process control systems are also becoming more sophisticated and precise. In the interest of system response capability, further research is necessary aimed at making boilers more responsive to system demands through anticipatory control concepts. This would improve system dynamic performance in situations where the system is responding to sudden loss of generation or unusually large load changes.

5.5.8 Balancing of Input and Output Power

Additional possibilities for improving system stability are based on measures to reduce the imbalance between input and output power of the turbine-generators during or immediately following the disturbance. These measures include the controlled fast closing of the turbine valves (temporary or sustained) and the dynamic braking through the application of shunt resistors at the terminals of the generators. As measures for sustained imbalances, generators or loads may be dropped, depending on the sense of the imbalance. Such means should be carefully investigated to insure that the overall system dynamic behavior is not adversely affected and that the post-disturbance system reliability is not significantly lowered.

5.5.9 System Reliability Monitoring and Evaluation

Problems of inter-area stability can be minimized if the systems are operated within adequate margins to allow for predetermined contingencies. To assure adequate margins, certain system parameters may need to be monitored and automatic methods of system reliability analysis should be developed.

The selection of parameters to be monitored will depend on the method of analysis to be used. This area needs considerable research, but investigations to date indicate that power flow, voltage magnitudes, and phase angles at key locations on the system can be used to obtain the operating state of the system. This would allow determination of the degree of stability and, hence, reliability of operation.[9,10]

Of considerable importance in some instances will be the development of techniques and equipment to provide the immediate knowledge of the occurrence of a contingency and to permit the prompt and best operating decision to be made. Fully effective implementation will require considerable technological development via an evolutionary process.

5.5.10 Research and System Stability

Increasing complexity of interconnected networks and a growing trend toward more sophisticated controls make it necessary that the available techniques of system stability analysis be improved and refined further so as to remain commensurate with requirements. Among the more important needs in this area are the following: (1) improved modeling of conventional boiler-turbine systems, nuclear reactor-turbine systems, hydro-turbine systems, and excitation systems, together with sufficient test data to establish and confirm the validity of such models; (2) increased computational efficiency of system stability investigations through use of meaningful equivalents, selective printout, and similar time-saving features; and (3) better understanding of the dynamic behavior of system load in response to changes in system voltage and frequency. A better understanding of the dynamic behavior characteristics of composite system loads is essential if system simulation of dynamic behavior is to be extended beyond the period of a few seconds with any degree of confidence in the results.

See footnote References, end of Chapter.

Progress for improved system dynamic performance has always occupied the attention of the industry. In the future, the need for continued progress will dictate an ever greater sense of urgency. Contributions toward this progress will continue to come from both individual and joint efforts of the operating utilities, the manufacturers of major electrical equipment, and the universities. As an example of the joint efforts that are possible, the Electric Research Council is sponsoring a two-year research program in the area of system reliability which is being pursued by six research organizations.[11]

Research activities in the area of system dynamic behavior will yield benefits for reliable system design and operation. Improved analytical techniques will provide the tools for more precise and efficient analysis and the means for achieving faster and more refined assessments of the dynamic performance aspects in an overall evaluation of system reliability.

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CHAPTER 6. DC TRANSMISSION

6.1 Introduction

Modern HV dc transmission is generally still considered to be in its infancy. The first commercial link, installed between the Swedish mainland and the island of Gotland in 1954, carried only 20 MW. However, between 1960 and 1970, eight additional lines have gone into service with power transfer capabilities ranging from 78 MW to 1440 MW. EHV dc projects with even larger transmission capabilities are now under construction. Table 6.1 lists pertinent data on the lines now in service or on order. As Table 6.1 reveals, a long overhead dc transmission line (Celilo-Sylmar) has been constructed in the United States. This line is nominally ±400 kV and is 846 miles long. Parameters of this order of magnitude are required for overhead dc transmission lines, if they are to be economically justified on the basis of the initial cost of their installation. However, other factors may override the "break even distance" concept and result in installation of overhead dc transmission lines at considerably shorter distances.

The many factors affecting the utilization of dc transmission are discussed in this chapter.

6.2 Lines

6.2.1 Selection of Operating Voltage

6.2.1.1 Trends in Voltage

In the past, operating voltages of dc transmission lines have been determined by integral multiples of available mercury-arc valves in converter stations. Existing dc lines are operating at 200 kV to 400 kV as a result of the cascade connection of two or more bridges rated at 100 kV to 133 kV each. The development of solid-state converters, or of lower rated single-anode mercury-arc valves, may remove this limitation in the future, and dc transmission systems will be available at any convenient voltage.

Economic considerations will continue to favor dc transmission wherever very long distance is involved. In these types of applications, economic considerations will also dictate large power ratings for such lines. In such instances, the voltage ratings may lie in the range from ±500 kV to ±1000 kV as future line capacities grow.

Dc overhead lines which must operate in series with dc cables are likely to be limited to much more moderate voltage levels. In such instances, maximum design levels for the cable may determine the system voltage. Extrapolation of limited data available on the dc cables indicates that operating voltages of ±500 kV should be readily attainable.

6.2.1.2 Costs

Costs of overhead lines, ac or dc, vary widely due to terrain, labor rates, and other factors. Due to limited experience with dc line construction, comparative costs of ac and dc lines are limited to those cases in which the lines have similar capacity. Under average conditions, dc overhead lines will cost roughly between 0.65 to 0.75 times the cost of a comparable ac line. Such a dc line would have a voltage-to-ground of approximately 0.87 times the phase-to-phase voltage of a comparable ac line and an equivalent current rating.

6.2.1.3 Capability

The power transfer capability of a dc line depends basically on the thermal capability of the conductors. When line lengths become very long, the resistive voltage drops, and the accompanying power losses may also become limiting factors. For dc lines, the conductor size will normally be limited by the corona and radio interference (RI) considerations, and the rating of the line will be limited by the power capability of the converter station at the line terminals. In special instances, the capacity of the link may be determined by the short-circuit capability of the ac buses at the line terminations.

The same system considerations that limit the amount of power that can be safely allocated to one line are equally applicable to dc or ac lines. However, the dc line, when equipped with suitable

TABLE 6.1

High-Voltage Direct-Current Power Transmission Projects in Commission or Under Construction

Date of commission	Line	Voltage to ground	Length of route (Miles) Cable	O.H.	Total	Power transmission MW
	PROJECTS IN COMMISSION					
1954	Gotland-Swedish Mainland	100	61		61	20
1961	English Channel	±100	34		34	160
1963	U.S.S.R. (Volgograd-Donbass)	±400		295	295	250
1965	Konti-Skan (Sweden-Denmark)	250	46	56	102	250
1965	New Zealand	±250	25	360	385	600
1965	Japan (Frequency Changer)	±125			0	300
1967	Vancouver Island	130	17.5	25.5	43	78
1967	Sardinia-Italy	200	73.5	185	258.5	200
1970	NW-SW Pacific Intertie	±400		846	846	1440
	PROJECTS UNDER CONSTRUCTION					
1971	Nelson River-Winnipeg	±450		600	600	1620
1971	Kingsnorth-London	±266	51		51	640
1972	New Brunswick Asynchronous Tie	80			0	320

ground electrodes or an insulated "neutral" conductor, can operate at half-capacity with one pole conductor faulted. Thus, for most outages caused by lightning, switching surge over-voltages, or conductor faulting, only half of the line capability would be lost during a fault.

6.2.2 Line Design

6.2.2.1 Performance Considerations

Dc lines must be designed to give the same high level of reliability as ac lines. Consideration is frequently given to the ability of a dc line to operate at half capacity with one pole (line or converter equipment) faulted. While this improves the reliability of a dc line, such performance depends on either the use of ground return or the provision of a lightly insulated neutral conductor. The former may be intolerable in many locations due to interference with other facilities or corrosion of buried structures, while the increased cost associated with the later must be carefully weighed. The ground electrode at most converter stations is located at a distance to avoid possible transformer saturation and corrosion.

Dc line design must also consider the effects of lightning flashovers and switching surge overvoltages on the insulation system. The method of current control on dc lines minimizes the danger due to lightning flashovers, but further data is desirable to enable the reduction of outage time to a minimum.

With appropriate control, protection, and system design, it is practical to limit the internal overvoltages to 1.7 pu and even 1.5 pu. Even when dc circuit breakers are used, it should be possible to design these circuit breakers to be compatible with the dc system such that line overvoltages do not exceed 1.7 pu. In a bipolar line, a ground fault in one pole will induce transient overvoltages on the other pole due to mutual coupling. However, with suitable dc line termination at the converter station, the maximum overvoltages anticipated would be below 1.7 pu. Consequently, insulation levels may be designed around the overvoltage factor of about 1.5 to 1.7, and protective gaps or lightning arresters should be so coordinated.

Because dc lines are not limited by such factors as skin effect, proximity effect, and reactive current components which affect the ampacity of ac lines, the conductor material can be used more efficiently. Hence, in many instances the complications associated with bundled conductors may be avoided for dc lines.

6.2.2.2 Radio Interference and Corona

The problem of radio interference (RI) and corona on dc lines is considerably different than that on ac lines for two principal reasons: (1) the nature of the space charge that builds up around a unipolar conductor and (2) the difference in the phenomena for a positive versus a negative polarity conductor.

While some research has been done in this area, a continuing theoretical and experimental effort must accompany further utilization of dc transmission. A summary of knowledge to date would include[1-4] these factors:

1. Lower signal-to-noise ratios are acceptable for dc lines than for ac lines.
2. RI from dc lines decreases during foul weather—an effect opposite to that for ac lines.
3. Most of the RI emanates from the positive conductor of a dc line.
4. Winds may cause RI to be considerably higher than under calm-air conditions, although this effect seems to be lessened when the positive conductor is upwind.
5. In the 500-kV potential range, the fair-weather corona loss for a dc line is of the same order of magnitude to slightly less than that for a 3-phase line.
6. The foul-weather corona loss of a dc line is on the order of five times its fair-weather loss in marked contrast to ac lines, where foul-weather corona loss can be up to 100 times the fair-weather value.
7. Dc corona losses seem to depend more on conductor height above ground than on conductor diameter, and line configuration has a much greater influence on corona losses on dc lines than on ac lines.

6.2.2.3 Harmonics and Inductive Interference

High-voltage dc converter stations generate strong harmonics, in particular the 5th, 7th, 11th, and 13th harmonics of the fundamental ac frequency. It is also possible for converter stations to generate the even harmonics because of dissymmetries in valve firing angles. Unless these harmonics are filtered out from both the ac and dc, they are propagated into the power transmission network where they can cause inductive interference with communications circuits.[5]

The size, rating, and cost of the harmonic filtering equipment depend upon the ac system impedance seen by the harmonics and the level of harmonics that can be tolerated without exceeding interference limits. In many cases, filter circuits can represent on the order of 15% of the cost of a converter station, and thus must be carefully considered in future designs.

Because harmonic filters are capacitive at the fundamental frequency, they provide reactive compensation. Filters can be designed to provide varying degrees of compensation and accordingly serve a dual role.

6.3 Terminals

6.3.1 The Basic Converter Circuit

The static converter circuit used for modern dc transmission is the Graetz bridge. As shown in Figure 6.1, this is a double-way, 3-phase, bridge circuit consisting of six controlled rectifying elements and a seventh "bypass" element. The bypass valve is primarily required in rectifier stations using mercury-arc valves to provide an alternate path for current during arcbacks so that the basic bridge circuit may regain control. In most instances, natural commutation will permit an inverter bridge to regain control without resorting to the bypass valve. In general terms, the circuit could be considered to function as a rectifier if the firing time of the valve is in the first quadrant of the ac cycle and to function as an inverter if the firing time is in the second quadrant. Adoption of this particular circuit has been predicated on its efficient use of converter transformer capacity, efficient use of the valves themselves, and its inherent ability to minimize unbalanced disturbances on the ac system.

The Graetz bridge is the basic building block of a converter station, and at the present time bridge circuits have been designed that are capable of voltage ratings of 150 kV per bridge and 1800 A. This results in a maximum power rating of 270 MW. When larger blocks of power are desired, such bridges can be connected in a cascade arrangement (in parallel on the ac side and in series on the dc side) to produce higher voltage ratings. One possible arrangement is shown in Figure 6.2. The bridges could also be connected in parallel on the dc side to produce higher current ratings. Similarly, the option is available to connect valves in series or in parallel in each arm of the bridge to increase the bridge rating (Figure 6.3). This, in fact, has been done in USSR's Volgograd-Donbass line where two valves in series are used in each arm of each bridge.

6.3.2 Converter Elements

6.3.2.1 Mercury-Arc Valves

All existing dc transmission terminals now in service except Volgograd and Donbass have been

See footnote References, end of Chapter.

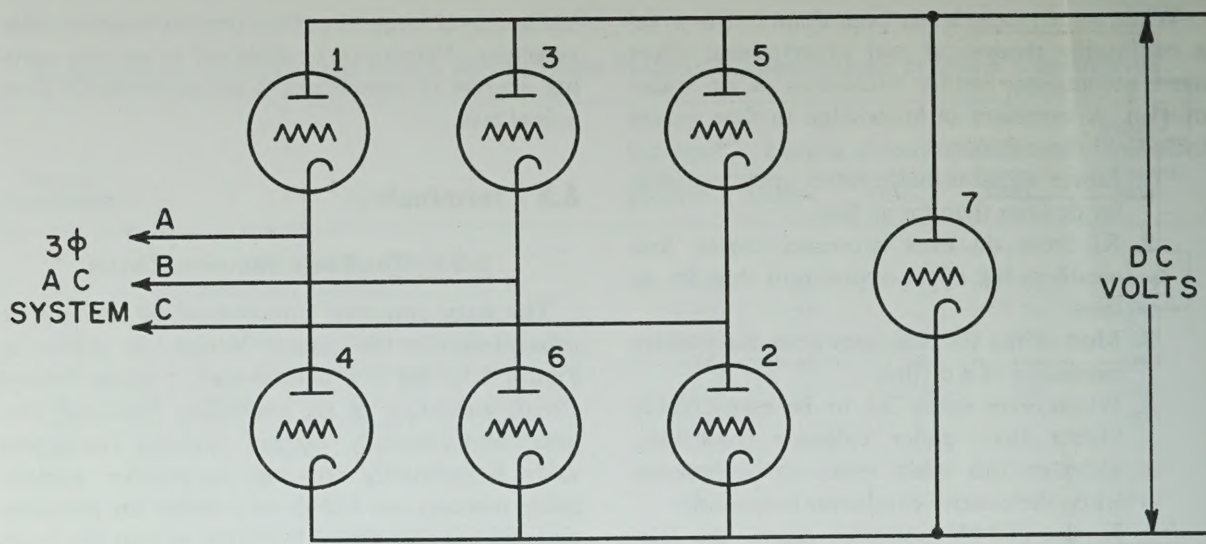

FIGURE 6.1.—The Graetz Bridge Circuit.

designed to use multi-anode, multi-grid, mercury-arc valves. The first such line (Sweden-Gotland) had a valve rating of 50 kV and 200 A, resulting in a bridge rating of 10 MW. The Pacific Northwest-Pacific Southwest Intertie line has a valve rating of 133 kV and 1800 A, resulting in a bridge rating of 240 MW. While these latter ratings are believed to be approaching the upper limit for this particular converter element, bridge ratings can be increased by inserting valves in series and/or in parallel in each arm of the bridge to obtain any desired power level. However, as ratings of these valves have been increased, difficulties have been encountered with arcbacks and an ensuing phenomenon known as consequential arcbacks (CAB's). Recent developmental work by the valve manufacturers appears to have greatly reduced the arcback problem, including CAB's, by improving the design of the electrodes in the valve and by new, more efficient, degassing processes.

Development work is also underway, particularly in England, on a simpler design of mercury-arc valves having only one anode and one control grid. These valves are also being designed to be suitable for outdoor mounting. Should such designs prove to be successful, the advantages are numerous. With a single anode, the need for balancing reactors used in multi-anode valves is eliminated. With a single grid, the peripheral components for voltage grading are eliminated. Most important of all, from an economic standpoint, is the possibility of eliminating the large valve halls now required to provide proper environments for mercury-arc valves.

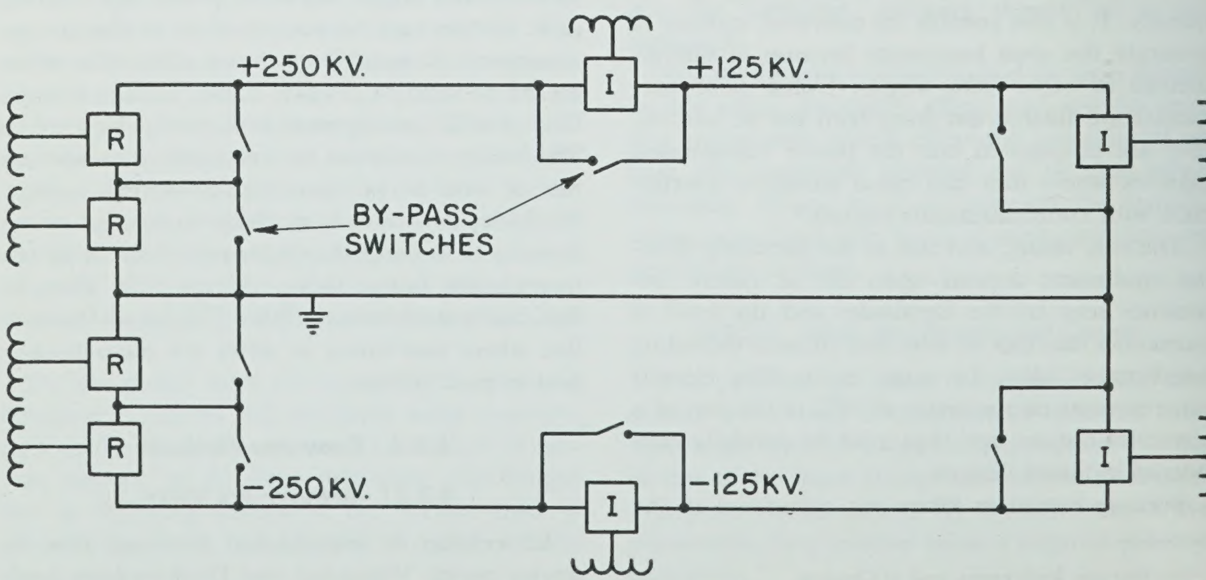

FIGURE 6.2.—Arrangement of Dc Line with Four Inverters at Different Locations.

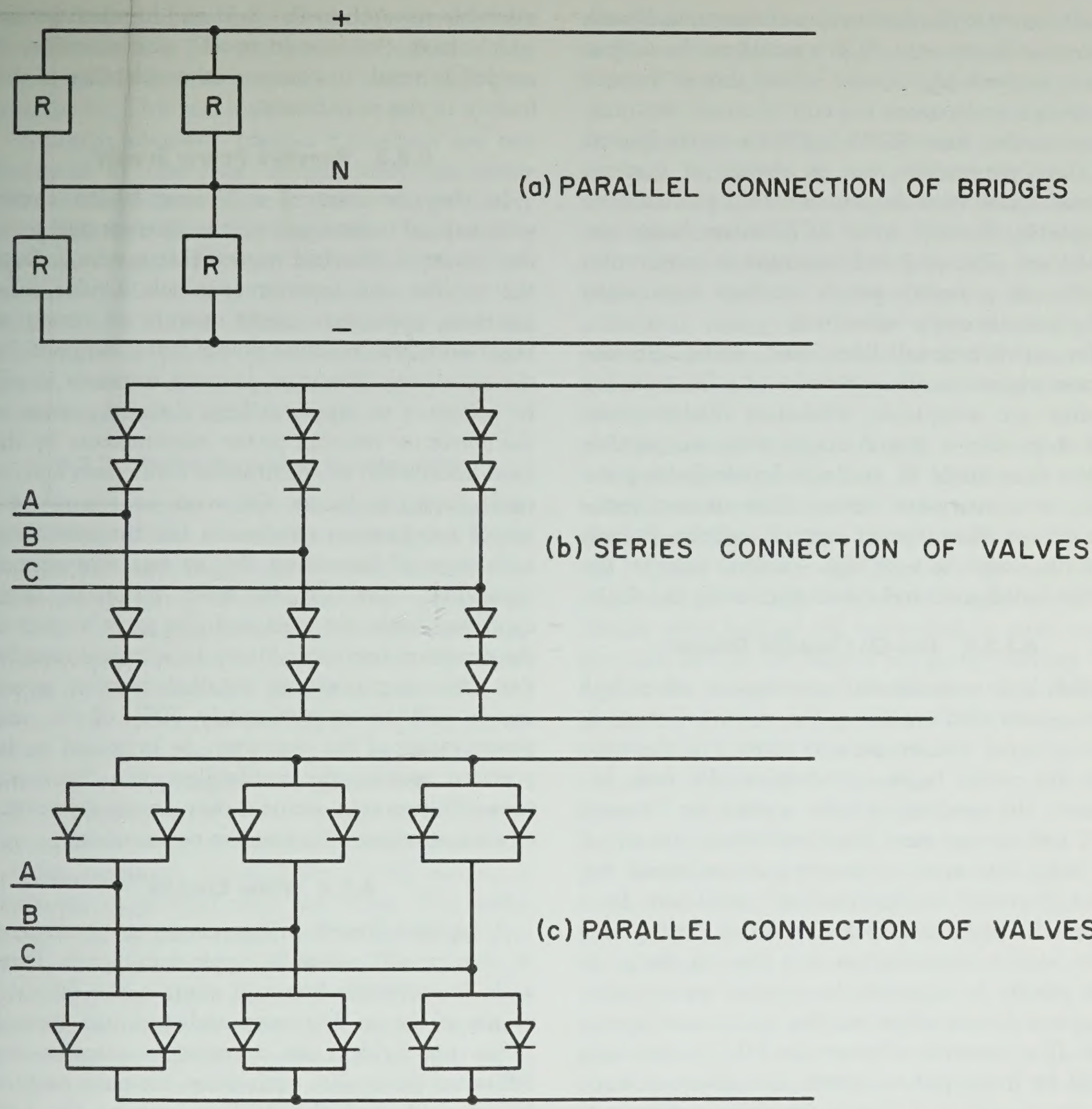

FIGURE 6.3.—Alternate Arrangements to Increase Converter Station Rating.

6.3.2.2 Semi-conductor Valves

In recent years, silicon-controlled rectifiers (SCR's) have replaced mercury-arc valves in industrial rectifier-inverter operations. Research work is far advanced towards adapting such solid-state devices for HV dc applications. In the United States, a prototype valve has been laboratory tested at 200 kV. In Sweden, a 50-kV, solid-state valve has been in service since 1967 as a replacement for one of the mercury-arc valves in the Sweden-Gotland line. The first full-scale, solid-state bridges will be added to the Gotland terminal in the near future. There are many advantages to such solid-state devices, but at present they are still considered somewhat more expensive than mercury-arc valves, particularly for large installations. Since individual solid-state valves are never expected to achieve voltage ratings comparable to mercury-arc valves, HV dc terminals will consist of large numbers of SCR's in series to achieve appropriate voltage levels and perhaps two or more strings in parallel to obtain the desired current rating. Such modular construction will inherently have the advantage of permitting the tailoring of voltage and current ratings to any desired level, and the small cost of individual units will permit considerable redundancy to improve reliability. SCR's must be protected against overvoltages, even of a transient nature, since a voltage breakdown of

a unit results in the destruction of that unit. If such protection is provided, SCR's would not be subject to any arcback phenomena, which should simplify the design and reduce the cost of converter-transformers. Also, since SCR's are not severely limited by their permissible rate of change of current, normal transformer impedances will probably be acceptable. Finally, some SCR valves being designed are oil-cooled and mounted in steel tanks, which will probably permit outdoor installation and eliminate costly valve halls.

For unidirectional lines, and under circumstances where the characteristics of a free-running rectifier are acceptable, solid-state diodes would probably offer a larger saving over comparable SCR's than would be available by eliminating the grids in mercury-arc valves. Free-running rectifiers do not allow current control, and the dc fault currents would be very high—limited only by the circuit inductance and speed of clearing the fault.

6.3.2.3 Turn-On/Turn-Off Devices

With both conventional mercury-arc valves and silicon-controlled rectifiers, the control feature is that a signal voltage permits control of the time that the valve begins conduction. In both instances, the conducting valve cannot be "turned off", and current must therefore commutate out of the valve into another current path to permit the valve to return to the "blocked" condition. In a Graetz bridge, the dictates of system voltage require such a commutation at a time in the cycle that results in appreciable reactive power consumption during either rectifier or inverter operation. If a converter element for HV dc terminals could be developed to permit free choice of both the "turn-on" and "turn-off" times, major advantages would ensue. By choosing commutation points near the points in the cycle where commutation voltages are near zero, the harmonic content on both the ac and dc systems would be greatly reduced, and the reactive power consumption would be minimized. It is perhaps even more intriguing to visualize an inverter with this capability which could deliver the power transmitted over the dc line to the receiving system at any reasonable, chosen power factor. Such a simple reactive power control could have far reaching benefits to a power system.

One such "turn-on/turn-off" device is the power transistor. However, at the present stage of development, both the low power ratings available in transistors and the high cost of such devices inhibit serious considerations for HV dc converters. Considerable research in this field and in other devices which have "turn-on/turn-off" characteristics is needed to result in commercial availability of this feature in the near future.

6.3.3 Reactive Power Supply

In the operation of a 3-phase bridge circuit with natural commutation, it is inherent that reactive power is absorbed from the ac system at both the rectifier and inverter terminals. Under some instances, converters might operate on strong ac buses with this reactive power being supplied by the ac system. However, in most instances it will be necessary to supply at least a major portion of the converter reactive power requirements by the local installation of synchronous condensers and/or static capacitor banks. On weak ac systems, the use of synchronous condensers has the additional advantage of increasing the ac bus short-circuit capability. However, in most instances static capacitor banks are used and also serve as part of the necessary harmonic filters. In a typical installation, the magnitude of installed reactive power supply will be approximately 60% of the real power rating of the converter. As indicated in the previous section, the availability of a "turn-on/turn-off" converter element may drastically reduce or even eliminate this reactive requirement.

6.3.4 Filter Circuits

A 3-phase Graetz bridge converter produces a dc voltage with a 6-pulse ripple component. Thus, a dc transmission line will contain the 6th harmonic of the ac frequency and multiples thereof. When two bridges are operated in cascade, and 30° out of phase with each other, the pulse number becomes 12, and the dc line contains the 12th harmonic and multiples thereof. One of the functions of the "dc smoothing reactor" is to minimize the harmonic content in the dc current. However, in many instances it becomes necessary to install shunt filters to minimize such harmonics so as to avoid interference with communication circuits. Obviously, the need for such filtering depends on whether the dc line is aerial or underground and on the proximity of sensitive communication circuits.

On the ac buses, a single bridge introduces the 5th and 7th harmonics and, to a lesser degree, other odd-numbered, non-triple-n harmonics. Cascaded bridges will produce principally the 11th and 13th harmonics and those of higher order. The presence of such harmonics in the ac system is likely to be troublesome, and filtering is normally

provided to minimize such effects. A common filter arrangement is to provide tuned filters for the 5th, 7th, 11th, and 13th harmonics and a low-pass filter for the 17th and higher harmonics.

Although normally triple-n harmonics are not generated by converter bridges, they can occur when the impedance of the ac system is particularly susceptible to a particular harmonic. The practice has been to add filters for the odd triple-n harmonics if and when initial operation of the line indicates such a need. Extensive analysis work has been done to permit predetermination of harmonics, but the changing nature of ac system impedance makes this a difficult task.

6.3.5 Valve Damping Components

Because converter valves are essentially switching devices which are subject to frequent rapid changes in both voltage and current, damper circuits are required to minimize the oscillations, particularly those associated with commutation. In mercury-arc valves, an anode reactor of perhaps one or two millihenries is placed in series with the valve. This reactor, in parallel with damping resistors, limits the rate of change of current (di/dt) in the valve so as to avoid arc quenching.

To limit the rate of rise of voltage at the end of commutation and to minimize voltage overshoot, a series resistance capacitance (R–C) circuit is connected in parallel with the valve. This valve damper circuit also damps oscillations in the forward voltage during nonconducting periods.

Although the di/dt limitations of solid-state dedices are less limiting, series inductances may also be necessary in solid-state valves. The parallel valve damper circuits are equally important in solid-state devices to control transient voltage rises and serve an additional purpose in becoming part of a voltage grading network to equally distribute the valve voltage among the many solid-state elements connected in series.

Effective valve damper circuits develop considerable power losses. Studies reported at the Institution of Electrical Engineers (IEE) special HVDC Conference in Manchester, England, in 1966 indicated that the losses in the valve damper circuits may amount to 0.25% of the rating of a converter terminal.

6.3.6 Converter Transformers

Transformer banks supplying one or more bridge converters, although basically considered as part of the ac equipment, must be especially designed to function properly in this application. Because the converter transformer may normally be considered as the only impedance in the commutation circuit, it must be designed to have a high leakage reactance. Conventional power transformers might have an impedance of 5%, but converter transformers, to limit the di/dt in the valves and minimize transient voltage stresses, are usually designed with impedances of 15% to 18%. The ratings of such transformers are generally 20% to 25% (in MVA) higher than the MW rating of the converter. This additional rating is due to the relatively poor power factor of converter bridges and the increased losses generated by the high harmonic content in the current.

The internal design of such transformers has more stringent requirements. In addition to the ac voltages, such transformers must also have additional insulation strength to withstand the dc voltage imposed between windings and ground. This additional dc voltage withstand requirement increases when bridges are connected in series, with the units at the line side of the group having the highest dc voltage stress. Due to the short-circuits produced by each commutation in the bridge, the transformer insulation is constantly subjected to transient overvoltages. Moreover, during disturbances in the bridge circuit, particularly primary arcbacks and CAB's, short-circuit currents of longer duration are imposed on the windings. Consequently, converter transformers are subjected to severe mechanical stresses and must be designed to withstand such stresses without failure.

Solid-state valves are not subjected to the arcback phenomenon, and, consequently, the mechanical stresses on converter transformers might be appreciably reduced. On the other hand, if higher di/dt values are permitted with solid-state valves, this would increase stresses in the transformer. Obviously, components of a converter terminal cannot be specified as isolated items but must be designed to coordinate into a compatible assembly.

Converter transformers will normally require automatic tap changers to permit maintaining of the desired dc line voltage without excessive changes in converter reactive power consumption. The range required in such tap changers will be dependent on the voltage (IR) drop in the dc circuit, the leakage reactance of the transformer, and variation of dc voltage. Normally a range of 15% to 25% is required.

6.3.7 DC Reactors

It is current practice to install large "smoothing reactors" in series with dc transmission lines at

each terminal. Acting either alone or in conjunction with shunt capacitors, these reactors provide some filtering of the 6- or 12-pulse ripple content produced in the converter bridges. This is necessary to minimize possible telephone interference and to permit operation of the converter bridges at low load levels without encountering the phenomenon of "discontinuous conduction" in individual valves. Generally the size of this reactor is in the order of from 0.5 to 1.0 H. Since the maximum reactance is required at low current levels, this reactor may be designed to become partially saturated at higher dc current levels. To minimize losses, the reactor is designed with a very high Q and is generally of an air core, iron-shell design.

The smoothing reactors also serve the function of limiting the di/dt during a dc line fault and are effective in permitting the dc line fault protection equipment to distinguish between a fault on the dc line and a fault in the inverter terminal.

6.3.8 DC Lightning Arresters and/or Surge Diverters

There has been considerable difference of opinion over the requirements of lightning arresters and/or surge diverters on dc transmission lines. The early dc line installations used a simple gap in lieu of lightning arresters, since no successful dc arrester had then been developed. More recently, several designs of lightning arresters capable of interrupting the dc power-follow current have been developed and are, in fact, scheduled for installations on the NW–SW Pacific Intertie and other future lines.

6.3.9 Control Equipment

6.3.9.1 General

A feature of dc transmission lines, frequently mentioned as one of the advantages of such lines, is the controllability of power flow. It is inherent in the nature of static converters that such power control is available, but to make proper use of this capability a sophisticated control system must be provided.

6.3.9.2 Constant Power Control

The majority of dc lines now in service function in a so-called "constant power mode". In a two-ended dc line, normal control of the constant voltage feature of the line is assigned to the controls at the inverter, and the power flow over the lines is varied by changing the current control order at the rectifier. By proper biasing such control at the rectifier, with a signal properly proportioned to any variation in dc line voltage, a constant power control ensues. In general, the constant current is maintained by comparing a current control order with a feedback signal of the actual current flow in the line and varying delay angle of the rectifier until these quantities match. There are, of course, many refinements to this fundamental control principle.

The current control order supplied to the rectifier should also be provided to the inverter with a small "current margin" signal of opposite polarity. If control of the power flow is to be possible from either terminal, a communication channel must be provided so that changes in the current control order can be applied simultaneously at both terminals. Under circumstances where the rectifier cannot deliver the ordered current at its minimum angle of delay, the inverter will take over the function of current control when the current margin has been exceeded and relinquish such control again when system conditions permit the rectifier to regain control.

6.3.9.3 Dynamic Controls

Some of the recent dc transmission lines, in addition to their constant power control mode, have other control modes available. The most common alternate mode is to vary the dc power flow as a means of regulating frequency. Such a concept is limited to dc lines between otherwide isolated ac systems. The option is available to the design engineer to have this control continuously available or to insert a "dead band" before this control mode becomes operable. Studies have also been conducted which indicate that a dc line might also have a continuously available control, responsive to ac system parameters, which would provide damping for system disturbances. The high speed with which the power flow over a dc line can be varied, independent of the power angle at its ac terminals, indicates considerable promise for future applications.

6.3.9.4 Multi-terminal Controls

All dc lines so far installed or on order are two-ended lines. However, as dc lines are applied in parallel with ac networks, the desire to tap such lines will increase. In a tapped dc line, minor modification in control concepts must be made, but the principal difference will be an increased need for communication channels between terminals to

provide adequate flexibility for the operation of such lines. Research studies indicate that control problems are not greatly increased for multi-terminal dc lines.

6.3.9.5 Line Protection

At the present state-of-the-art, with no dc breakers currently available, an important feature of dc line controls is the line protection equipment. Control systems should include the capability to rapidly sense faults on the dc line, discriminate between such faults and faults in the converter terminals, and take the proper action. The normal function of such line protection equipment, once having determined that a fault exists, is to maintain the inverter in the inverter mode and to rapidly change the rectifier to inverter mode so that the fault current is interrupted and the line quickly discharged. By choice of a judicious delay time, restarting of the dc line may then be attempted, and, if the fault was of a transient nature, the total outage time of the line can be reduced to a minimum. Features can be incorporated to allow the operator to choose the number of restart attempts before locking the line out when the fault is of a permanent nature.

6.3.9.6 Other Necessary Control

Dc line control systems will also require other special features such as protective action for disturbances within the converter, the supply of auxiliary power to bridges at elevated dc voltages, a means of supplying control pulses to bridges at various voltage levels, etc.

6.3.10 DC Circuit Breakers

Since all present dc transmission lines are two-ended installations, the need for a dc breaker has been obviated by utilizing the converter controls to interrupt current. However, if a dc breaker were available to permit easy and reliable tapping of dc lines, additional uses for dc transmission might be found. The fundamental problem in developing a dc breaker arises from the constant value of dc current or lack of a cyclical "current zero" such as is utilized in ac breakers for interruption. Conceptual ideas have been developed to design dc breakers by various means of artificially producing a current zero. There are currently at least two active research projects in the United States aimed at developing and evaluating dc breakers in which the principles of operation are entirely dissimilar. Other concepts are under development abroad.

6.3.11 Radio Interference and Inductive Coordination

Due to the harmonic generation in converter stations and the resulting injection of harmonics into both the ac and dc transmission system, special measures must be taken to prevent interference with communication circuits such as telephones and railroad signals. In the case of the high order harmonics and high frequency "noise" generated within the converters themselves, measures must also be taken to prevent radio interference.

The filtering previously described is the main protection against the principal harmonics that are known to be characteristic of converters. However, in the immediate vicinity of the converter station, radiated noise must be minimized by effective electrostatic shielding. It is established practice in populated areas to make the entire valve hall a Faraday cage to squelch radiation from the valves themselves.

In some cases, electrostatic shielding enclosures are also being added to cover much of the outdoor equipment in dc transmission terminal stations. Complete electrostatic shields, 40 to 50 feet high and covering areas of several acres, become rather expensive, especially if they must be designed with sufficient strength to support heavy snow and ice buildup.

6.3.12 Land Requirements

In planning an HV dc converter terminal station, one of the problems that confronts design engineers is to determine fairly accurately the size and shape of the site.

In a 1440-megawatt terminal now under construction, 21.2 acres are required to accommodate equipment and facilities utilizing today's dc converter techniques. This acreage includes a service building, valve hall, converter transformers, valve damping facilities, ac filters and power factor equipment, dc filters and miscellaneous dc equipment, ac and dc towers, the necessary ac and dc buses, oil-handling equipment, outdoor degassing facilities, entrance and service roads, and an employee parking area. For this station, the ratio of site area to electrical capacity is 640 square feet per megawatt. This ratio should provide a fair basis for estimating site requirements for other installations employing comparable equipment and voltages.

Extensive interest in the possible use of solid-state devices in HV dc is evidenced by several active developmental efforts, by one trial installa-

tion in the Gotland link, and by a proposal to supply solid-state HV dc converter equipment in at least one major project.

Solid-state HV dc introduces prospects of space saving in several ways: (1) greater permissible rate of change of current could mean lower reactance and, hence, smaller transformers, (2) smaller firing margin could mean higher power factor, requiring less space for shunt capacitors, (3) although heat removal would be as much or more than for gas-filled valves, the control and distribution is much less critical and would be expected to demand less space, (4) it might be possible to locate solid-state converter assemblies outdoors in oil-filled tanks, thus eliminating valve halls, and (5) maintenance space might be considerably less than degassing space and equipment.

6.4 Economic, System, and Future Considerations

6.4.1 Economic Considerations

Fundamentally, the transmission of power by direct current has several characteristics which distinguish it from its ac counterpart. Some of these characteristics are obviously instrumental in reducing the cost of transmission. The economic effects of other characteristics are less obvious and, indeed, may have opposite effects in different applications. Some of these characteristics may be listed as follows:

1. The construction of the transmission line, overhead or underground, is less expensive
2. At present, for comparable rated lines, the transmission losses are reduced
3. Dc transmission cable lines do not become limited by reactive charging Mvar
4. The transfer of power on a dc line is readily controllable
5. Modern dc lines do not add appreciably to the short-circuit capacity of their receiving buses
6. The asynchronous nature of dc lines may be an asset in some situations
7. Dc transmission terminal stations are appreciably more complex and expensive than their ac counterparts.

With regard to item 7, firm data is difficult to establish. However, the cost of a dc transmission terminal will generally be in the range of \$25 to \$30 per kW per terminal and, in some cases, may go to \$35. This cost does vary as an inverse function of terminal size. A comparable ac transmission switching station might cost \$6 to \$8 per kVA per terminal. When this difference in terminal costs is considered in conjunction with the possible savings indicated in items 1, 2, and 3 above, a concept of break-even distance is evolved and is the justification of most of the lines in Table 6.1. This economic break-even distance will vary depending on the terrain, labor rates, and other factors, but is generally agreed to be between 20 and 50 miles for underground transmission and between 400 and 1,000 miles for overhead lines. Of the nine lines shown to be in service in Table 6.1, six include considerable lengths of underwater cable as part or all of the justification for the use of dc. The Japanese Frequency Changer (listed in Table 6.1) has essentially no length, and dc was chosen to permit the interchange of power between two systems of different frequencies. The Volgograd-Donbass overhead line is only 295 miles long and is considered as a prototype for future, larger and longer, transmission schemes.

6.4.2 A System Aspect: Parallel AC–DC Operation

Prior to the initial operation of the dc line to the Island of Vancouver, all dc transmission lines were ties between otherwise isolated ac systems. For applications of that nature, the constant power dc link has special advantages. It permits the interchange of power between systems in which the degree or mode of frequency control is different (English Channel line). In some instances, such as the Sardinia-Italy line, it can be utilized as a supplementary control of frequency.

In the United States, however, most applications of dc transmission lines will be operated in parallel with existing ac ties and must be controlled to be compatible with the needs of the ac system. With the present constant power mode of operation, a dc line may add to the stability of an ac network under some circumstances but be of less stabilizing influence than an ac line in other instances. The principal operating characteristics for this type of dc line are

1. The power flow over the line can be specified and is independent of power angle or system voltages (within reasonable limits)
2. The desired power can be delivered to an ac bus without appreciably increasing the short-circuit duty on the bus
3. In most instances, a bipolar dc line will provide reliability characteristics equivalent to a double-circuit ac line, since either

pole can continue to function when line or terminal faults cause a single pole outage.

Characteristics such as these are difficult to evaluate in terms of their net dollar value. Obviously, any resulting economic benefit would vary greatly between different installations. However, they are factors which should be evaluated by system planners when comparing the relative merits of ac and dc lines.

6.4.3 Future Considerations

6.4.3.1 Introduction

Modern dc transmission lines are generally recognized today as an alternative means of transmitting blocks of power. In the manner in which they have been used to date, the choice between ac or dc is predicated on an evaluation of the installation cost of the two. However, a dc transmission line is also a new tool with some unique characteristics. Studies are being conducted to further evaluate possible future applications for this tool, both at its present stage of development and considering its anticipated improvements in the future. Some thoughts on such possible future applications are outlined briefly in this section.

6.4.3.2 New Modes of Control

Perhaps the most intriguing characteristic of a dc transmission line is the complete and rapid control of power flow available to the operator of such a line. In the conventional constant power mode, this controllability can be utilized to maintain a fixed power flow over the dc line through the full range of normal operating conditions in the ac system at the line terminals. However, the rapid speed of response in power control of the dc line can also be used to provide damping for ac system disturbances. Studies in this country and abroad, both on analog models and on digital computers, have examined this possibility and have indicated great promise for this application.

In general, power system swings develop at a comparatively slow rate due to the inertia inherent in such systems. Thus, a relatively weak ac system may develop oscillations leading to instability, but the time required to reach instability may vary from a fraction of a second to several seconds or longer. By contrast, given the proper information, a dc line can change the transfer of power between two points in an ac system in a matter of a few milliseconds. By injection of even relatively small amounts of stabilizing power, at an early point of a disturbance, the possibility of instability can be appreciably decreased. Controls can be devised to provide such damping through "on-line" dynamic controls using any one of several ac system parameters as an input.

It has also been demonstrated in model studies that a dc line can function without an "on-line" control as a constant power device and can receive specific power order changes concurrent to any one of several system outages. For example, a simple electronic circuit can monitor the power flow of a particular line, or from a given machine, and store a "power order change signal" for a dc line. In the event that the monitored line or machine developed a fault and was tripped out, an auxiliary contact on the breaker could release the stored information and make a discrete power order change on a dc line. Due to the controllability of the power flow on the dc line, maximum and minimum limits can be applied readily so that any automatic request for power changes will not exceed the limits so chosen.

The preceding paragraph outlines a basic approach for utilizing a dc line to improve the stability of ac systems. Work in this area has barely begun, and full evaluation of such application should be made by power system planners, whenever appropriate, using digital computer programs with the capability of properly representing dynamic and responsive dc lines.

6.4.3.3 Multi-terminal DC Lines

The dc lines currently in service or under construction are basically point-to-point, two-ended lines. The Kingsnorth-London project (Table 6.1) has three geographically distinct terminals by placing the positive and negative poles of one end of a bipolar line at different locations. However, from a technical standpoint, it is still a two-ended line. Future exploitation of dc transmission will demand the development of multi-terminal lines.

One arrangement of multi-terminal dc transmission which may have some application is shown in Figure 6.2. In effect, this shows a four-bridge rectifier station supplying four individual inverter bridges at four different geographic locations. Basically, this requires no new technology but has serious drawback in that little flexibility is provided in the choice of power flow to the various receiving stations. However, as a means of injecting power into various points in an urban ac network, this arrangement might prove feasible.

A simple but more flexible tapped dc line is

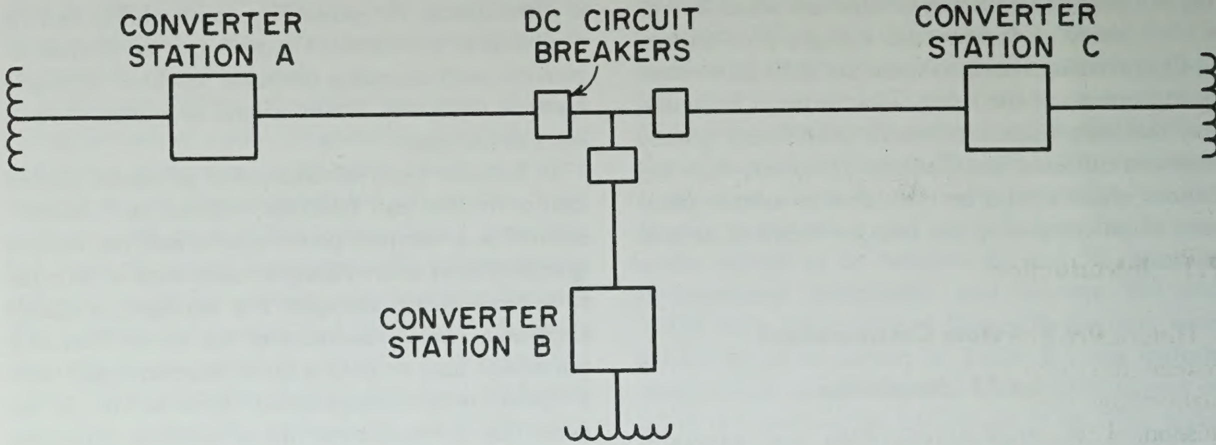

FIGURE 6.4.—Single Line Diagram of a Tapped Dc Line with Dc Circuit Breakers.

shown in Figure 6.4. It involves relatively little new technology except for the direct-current circuit breakers. Mainly, modifications of control circuitry would be required to initiate such a three-terminal line. However, if such a line were to be considered as a major bulk-power-tie line between three different points in an ac network, it would be essential that a dc circuit breaker be available so that a faulted section of the dc line could be removed without interfering with the operation of the remaining two terminals. Thus, full development of dc transmission will be impeded until a technologically feasible dc breaker is developed and made available at a reasonable price. As mentioned elsewhere in this report, research work aimed at filling this need is underway.

Considerable study is also required to assure the development of adequate control systems which will permit proper operation of multi-ended dc lines. The control concepts necessary for constant power operation of multi-ended lines are not expected to be unduly complex; however, a dynamically responsive multi-ended dc line may indeed require a sophisticated control system to take advantage of its full potential.

6.4.3.4 *Advanced Converter Technology*

As discussed in section 6.3.2.3, there would be several distinct advantages if a turn-on/turn-off valve were developed for use in a converter station. Additional studies should be undertaken to fully explore the operational features of such converters and to determine their limitations. From a theoretical evaluation, it would appear that operation of converters close to unity power factor point would reduce the cost of converter terminals by eliminating a considerable part of the var supply now required and by minimizing the filtering required at converter terminals. (Reactive power supply and harmonic filters account for about 25% of the cost of modern converter terminals.) Several devices do exist, developed for other purposes, which show promise of achieving a low-loss, high power-level, turn-on/turn-off element for converter bridges. Further evaluation by the power industry of how such converters might be applied is required to spur further activity in the development of such devices.

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CHAPTER 7. UNDERGROUND TRANSMISSION

7.1 Introduction

Historically, the development of electric power systems has been based on the concept of using high-voltage overhead lines for bulk power transmission. The use of underground cable for this purpose has generally been limited to the short lengths required in extremely congested areas. Two principal reasons are (1) as transmission voltages have risen over the years, the technology for overhead lines has been available, while the technology for underground cables of equivalent capability has generally lagged, and (2) the cost of underground transmission has been, and remains, much higher than for equivalent aerial circuits.

In the United States, the cost ratio of underground to overhead bulk power transmission lines can range from 10:1 to 40:1 for equal capacity. Many factors influence this cost differential, and future technological developments may be effective in reducing it, and, in urban and suburban areas, the rising cost of rights-of-way alone for EHV overhead lines will provide significant reductions. However, the differential is large, and since as much as 60% of underground transmission costs can be attributed to installation labor, the prospects for major reductions in the ratio are not encouraging. It therefore appears that overhead transmission will continue to be dominant, with underground being used in those instances where technological and social conditions leave no alternative.

In April 1966, the Federal Power Commission issued a report on underground power transmission[1] which studied in depth the current state-of-the-art and included detailed analyses of the components of costs and prospects for their reduction. The coverage of underground transmission in this report will accordingly present subsequent progress and indicate trends based on the results of more recent research.

Since most recent research efforts have been directed toward ac cables, this chapter is exclusively ac oriented. However, interest in dc is increasing (See Chapter 6) and most of the technology reported here is equally applicable to dc cables. The present program of the ERC Underground Transmission R&D Steering Committee includes plans for direct evaluation of dc cables. If further information is desired, the FPC Committee Report, reference 1, should be consulted.

7.2 State of the Art

7.2.1 Present Practices and Trends

There are two principal types of high-voltage underground power transmission cables in use at the present time—the self-contained and the pipe-type.[1]

Each phase of a self-contained cable consists of a conductor formed over a hollow core insulated by oil-impregnated paper and protected by a lead or aluminum sheath. The hollow core is filled with oil at one atmosphere-of-pressure to prevent voids from forming within the insulation structure.

In the case of pipe-type cable, the phase conductors are usually segmental, have an impregnated paper insulation, and are covered with a combination of metal and synthetic tapes for shielding purposes. Three of these cables are pulled into a pipe which is then filled with oil or gas under a relatively high pressue of 13 to 15 atmospheres.

The pipe-type cable is inherently more rugged and can be installed in longer pulling lengths, resulting in fewer splices and few manholes. These characteristics give important economic-advantages over self-contained cables. As a result, pipe-type cable predominates in the United States, as shown in Figure 7.1.[2] It is of interest to note that the first energization of pipe-type cable to be operated at 345 kV occurred on May 1, 1964 in New York City and was 24 km (14.9 miles) in length.

The technological and economic problems associated with the use of high-voltage pipe-type cable are well summarized in the following quotation from reference 2:

> With currently available insulation systems, the dielectric losses increase rapidly with increases in voltage levels. For

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See footnote References, end of Chapter.

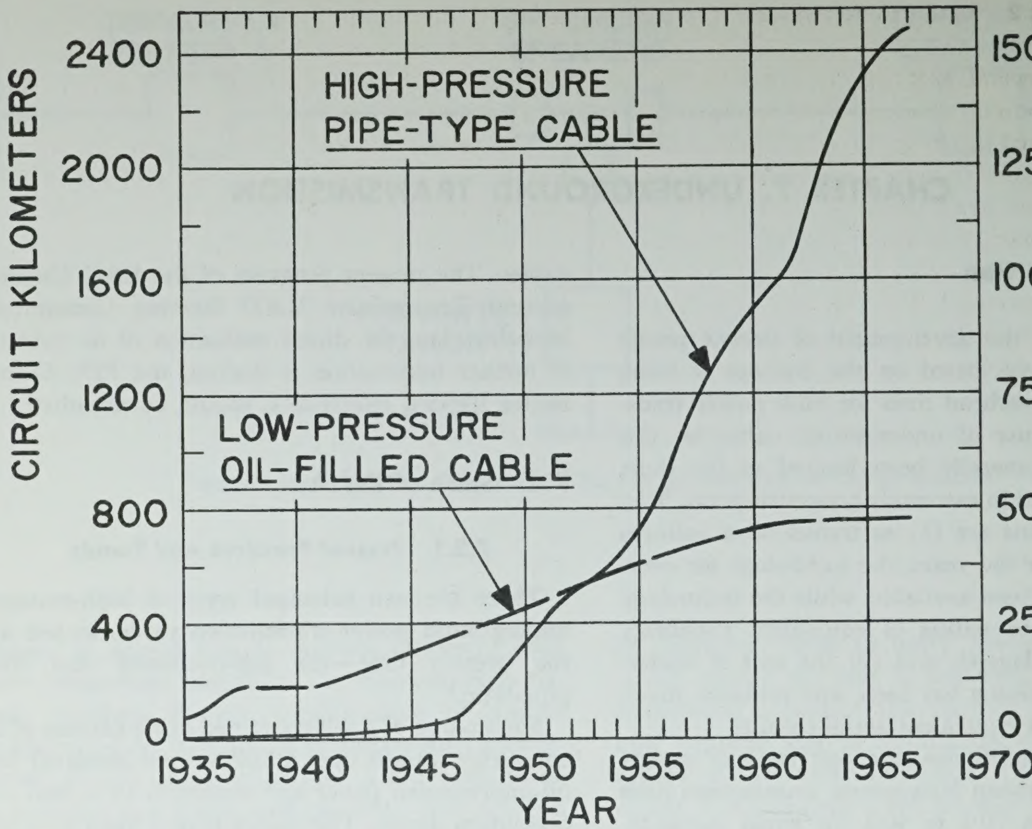


FIGURE 7.1.—Underground Transmission Cable in the United States (69 kV to 345 kV).

a 345 kV cable on a typical duty cycle, dielectric loss can run as high as 26 watts per circuit meter! Because the total permissible loss on such a line is about 72 watts per meter, not much room is left (46W/m) for I^2R losses in the conductor. The result is that the powei -transmission capability of the 345-kV system is only 4.2 times that of the 69-kV system. In overhead transmission, a quintupling of voltage operation would increase capability about 25 times.

At 345 kV, the average line cost for a 48-kM underground circuit in a suburban area alone would be around $430,000 a km as against $74,000 a km for an overhead circuit—but the overhead line would have a capability more than twice that of the underground line (1050 MW vs 484 MW). In addition to the line cost, the underground circuit would require $3,760,000 for compensation and terminal facilities not needed for overhead, so that the cost per megawatt-kilometer would be $1,050 for underground against $70 for overhead.

A third type of cable, now entering the high voltage field, is extruded synthetic insulated cable. Materials such as polyethylene, cross-linked polyethylene, and ethylene-propylene rubber are now being used up to 138 kV and are being tried experimentally at 230 kV.

One of the most important factors limiting the capability of underground power cables is the generation and dissipation of heat. A large percentage of the research presently underway is aimed at this problem. Some of this research is on the forced-cooling of existing types of high-pressure oil-filled cables (see section 7.3). The results which may be expected are shown in Figure 7.2,[2] and verification of such data is being carried out by individual utility companies.[3]

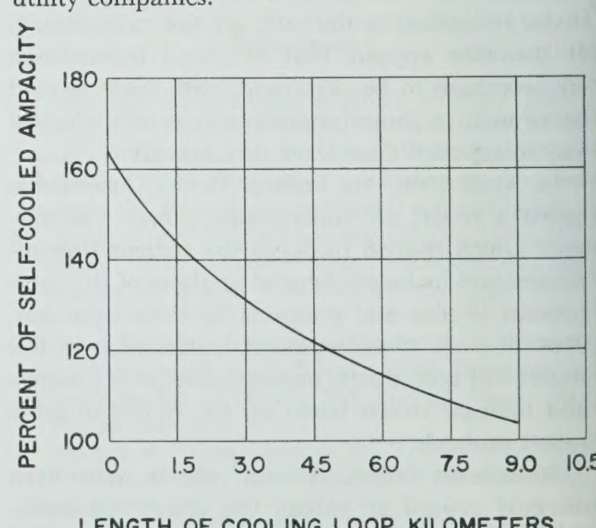


FIGURE 7.2.—Typical Capacity Increase Obtainable with Force-Oil Cooling.

See footnote References, end of Chapter.

7.2.2 Research Activities

There are several areas of current research in underground power transmission technology that will be mentioned briefly at this point. Some of this research is discussed in more detail in later sections, depending upon availability of information. As already mentioned, a research project was aimed at increasing the capability of pipe-type cables by using forced cooling.[4] The project investigated forced-cooling techniques applicable to presently used pipe-type cables, actual cooling systems, and the economic advantage of forced-cooling. The results of this investigation are encouraging and are discussed in more detail in section 7.3.

A five-year research project investigating synthetic insulation for extra-high-voltage cables was recently completed for the Edison Electric Institute by the Illinois Institute of Technology Research Institute. Such insulating materials can be utilized in cable in various ways. Extruded insulation has been mentioned already, of course. However, a suitable material could be prepared as a film and slit into tape for application in the same manner as an oil-impregnated paper insulation and then pressurized with a liquid or gas. Physical problems of impregnating such a build-up of synthetic tape has led to efforts to develop a synthetic "paper" which would be made up of synthetic fibers and have sufficient porosity to permit impregnation with a compatible fluid.[5]

Two of the urgent needs of the power industry are the development of 500-kV cables and extending the voltage rating of extruded dielectric cables. These are the immediate objectives of a multimillion dollar research project funded by the Edison Electric Institute. This research is being conducted at a special test facility constructed at a cost of approximately $5 million at Waltz Mill, Pennylvania. The entire Waltz Mill research program is expected to last 10 years or more and will test underground transmission systems in the range of 115 kV to 750 kV. Tests will be conducted on solid synthetic insulations, as well as synthetic-oil and paper-oil insulations. One-thousand foot cable samples will be energized and loaded at rated voltage in pipes that can be heated to simulate various ambient temperature conditions.

Through the Edison Electric Institute, the Electric Research Council is sponsoring a research project at the Massachusetts Institute of Technology to determine the feasibility of using gas-insulated concentric lines (also known as compressed gas insulated cable) at voltages in excess of 500 kV. Compressed gas insulated cables are discussed in section 7.4.

Studies are also underway to explore the possibilities of resistive cryogenic cables (cables operated at temperatures of several hundred degrees Fahrenheit below zero, but not in the superconducting mode). One of these investigations is sponsored by the Electric Research Council. Resistive cryogenic cable is discussed further in section 7.5.

A research effort has been underway for two years exploring the feasibility of superconducting ac power cables. Based on information gained thus far, superconducting ac cables may be economically advantageous for transmitting power in the 1,000 to 10,000 MW range. It is estimated that a 12-year, $8 million program would be required before superconducting cables could become part of an operational system. Superconductivity is discussed further in section 7.6.

7.3 Forced Cooling of Pipe-type Cables

7.3.1 Introduction

At a particular level of transmission voltage, the power transfer capability of underground cables is limited by the ability to dissipate heat due to losses in the cable. Without sufficient heat dissipation, the temperature of the cable rises to a point where thermal damage to the insulation occurs, leading ultimately to a cable failure.

In the case of self-cooled cables, all of the heat caused by cable losses is dissipated to the ground. Thus, soil conditions, ambient temperature, and proximity to other sources of heat affect the rating of an underground cable system of this type. If a coolant is circulated through the cable, or in a separate channel close to the cable, heat is carried away both by the coolant and by the surrounding soil, making an uprating of the cable possible. The following sections describe one method of forced cooling of pipe-type cable.

7.3.2 Description of Method

The forced cooling methods considered in a recent study[4] can be categorized according to the method of circulating the coolant. These are identified as "integral channel cooling" and "separate channel cooling". In the integral channel cooling system, the coolant becomes one of the components of the cable, and its electrical, as well as thermal

See footnote References, end of Chapter.

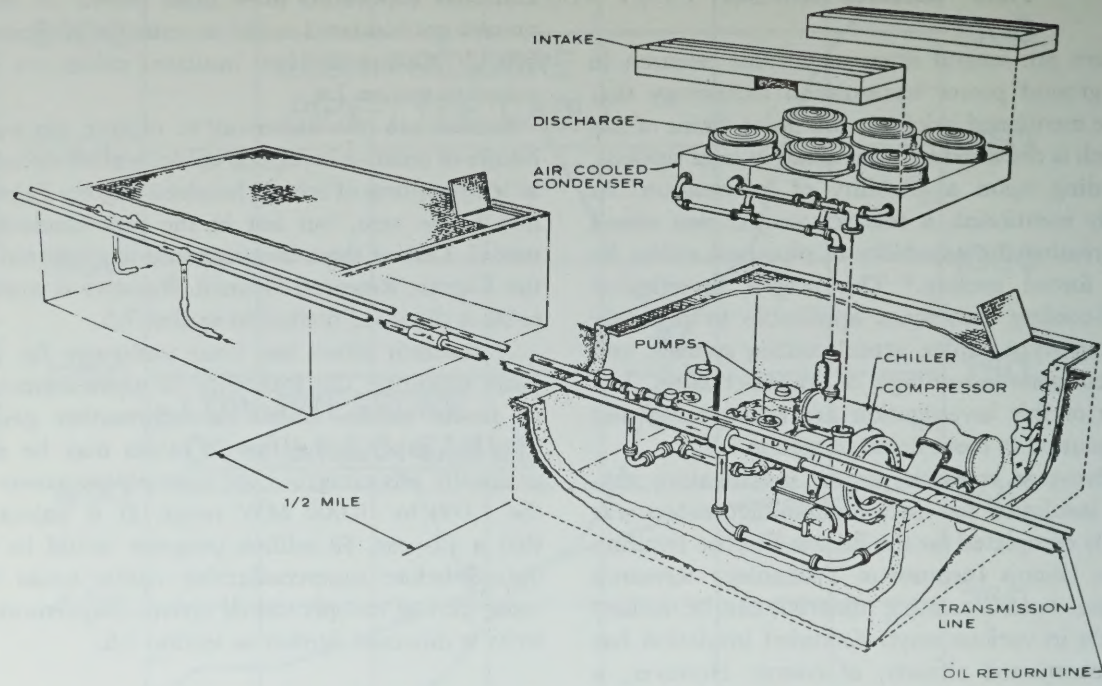


FIGURE 7.3.—Circulating Oil Cable System.

and hydraulic properties, are important. The separate channel cooling system, in contrast, has thermal coupling with the cable system as the prime consideration.

Of these two methods of forced cooling, the integral cooling system gives a higher cable rating at a lower power transmission cost per MVA mile and is preferred for near-term application. The separate channel cooling system does have sufficient attractiveness to warrant further study. The general layout of an integral channel, forced-cooling system is shown in Figure 7.3.[4]

The uprating of a cable by integral channel, forced-cooling methods is strongly dependent on the length of the oil flow path, on the inlet temperature of the coolant, and, to some extent, on the particular grade of electrical oil used as the coolant. Figure 7.4 shows how cable ampacity is affected by these various factors.[4]

Heat removal from cable joints also poses problems in the case of uprated cables. This is due to the poorer heat transfer characteristics of the taped splice, which has thicker insulation than that on the cable proper. These splice hot spots can be alleviated by lowering the temperature of the cooling oil and by inducing turbulent flow of the coolant at the joint.

Pipe-type cables are terminated in oil-filled porcelain bushings called "potheads". In general, the ratings of available potheads are not sufficient to meet the cable ratings of forced-cooled cables. It is difficult to cool the potheads by circulating a coolant inside the porcelain bushing, because the

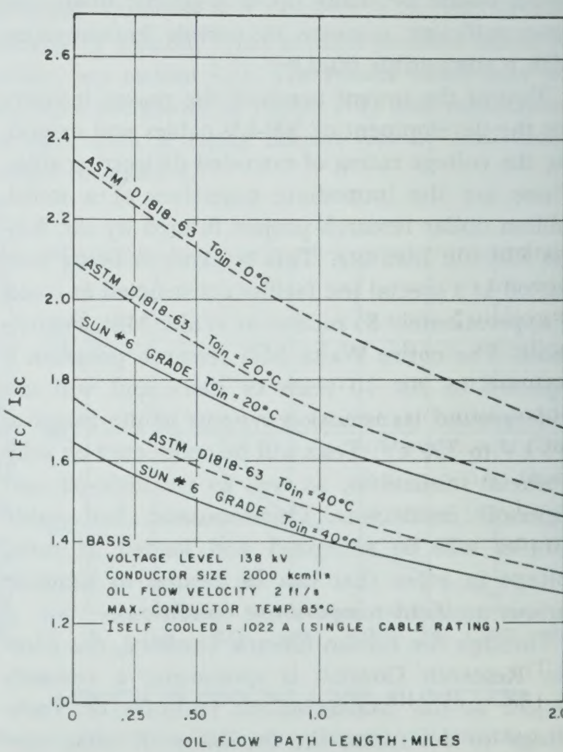


FIGURE 7.4.—I Forced Cooled/I Self Cooled vs Circulating Oil Flow Path Length.

See footnote References, end of Chapter.

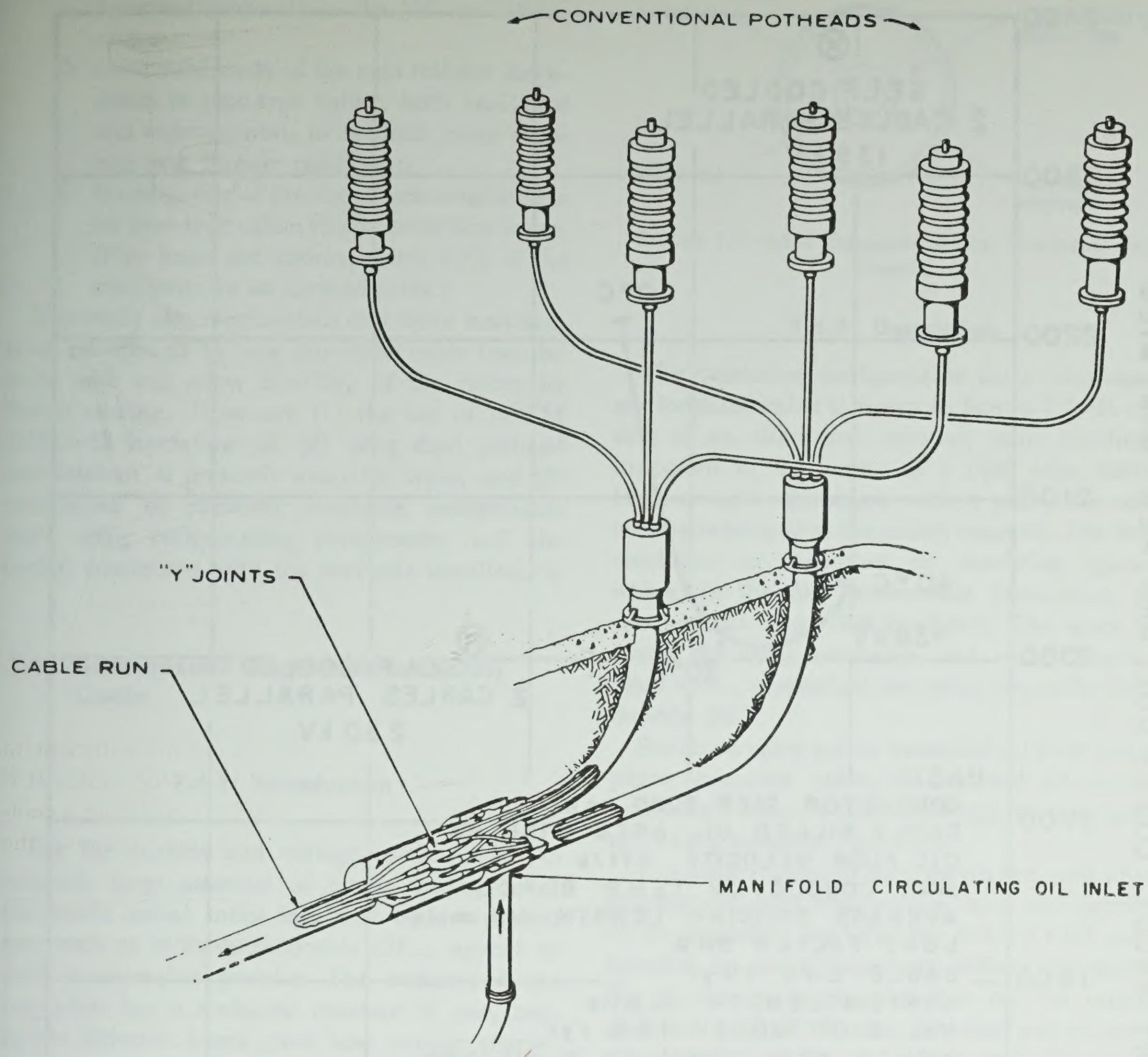


FIGURE 7.5.—Forced-Cooled System Termination.

coolant must be at a high enough temperature to prevent condensation on the external surface of the porcelain bushing. One approach to cooling the potheads would be to enclose the entire cable termination in a refrigerated, controlled atmosphere, utilizing, say, sulfur-hexafluoride gas (SF_6); such a method would need considerable development. An expedient that may provide an interim solution is to use a Y joint and dual potheads. This arrangement is shown in Figure 7.5.[4]

7.3.3 Results of the Study

The general results of the study of forced cooling of 138- and 230-kV pipe-type cable indicates that an uprating on the order of 100% or more at an overall cost savings in comparison to other alternatives is possible. These results, as indicated in Figure 7.6, are based on the use of dual pothead terminations.[4]

Additionally, the investigation revealed that the following points need further study:

1. Development of the most feasible refrigeration package to be used in the forced cooling of pipe-type cable
2. Investigation of other electrical insulating oils to determine one that is best suited based on dielectric characteristics, compatibility with insulation impregnation oils, heat transfer characteristics, hydraulic characteristics, availability, and cost
3. The effect of varying the pipe size on the performance of the coolant
4. A design study of pothead terminations of

See footnote References, end of Chapter.

See footnote References, end of Chapter.

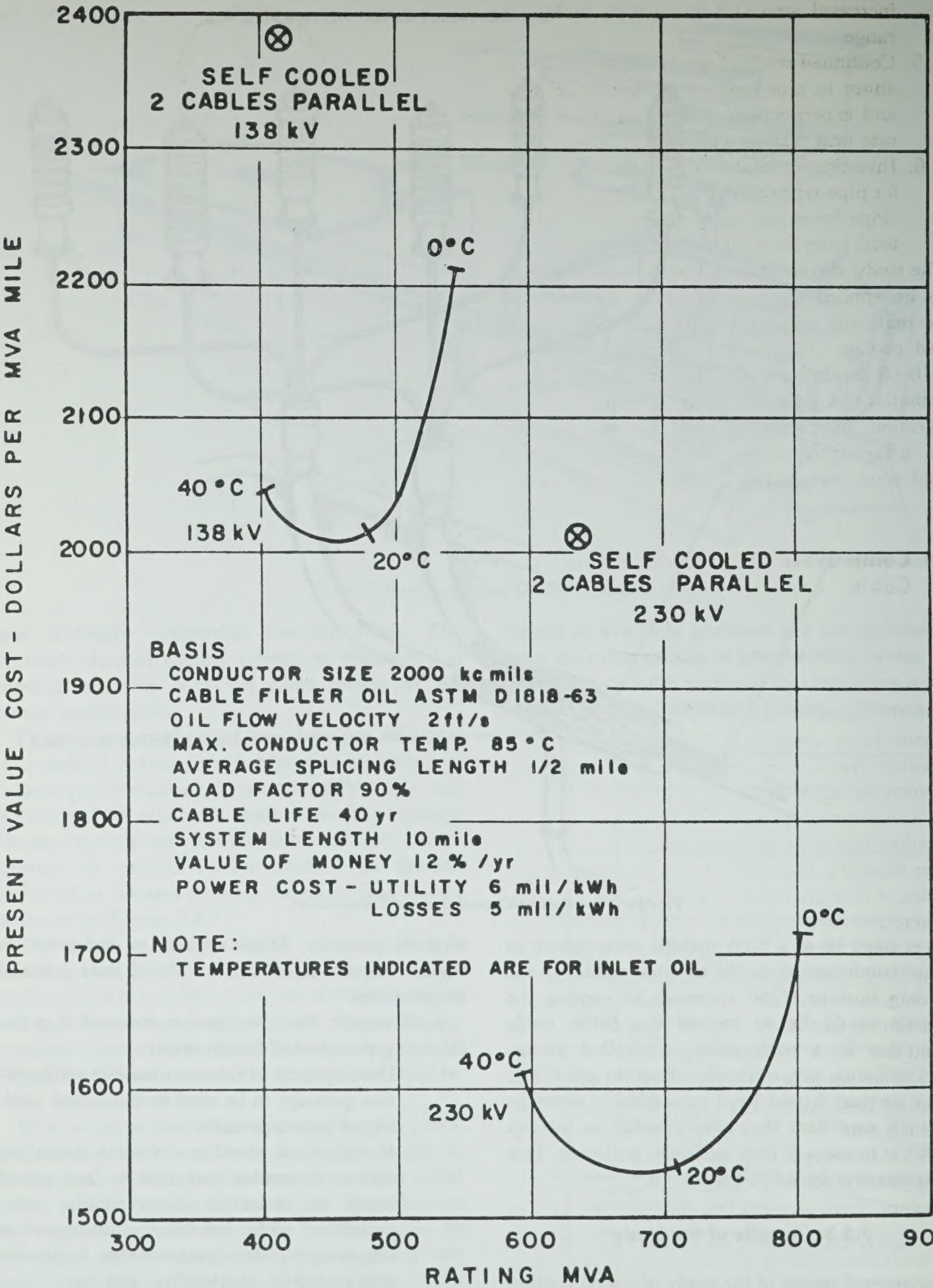


FIGURE 7.6.—Circulating Oil Cable System Transmission Cost at 138 kV and 230 kV.

increased ampacity in the 138- to 345-kV range

5. Continued study of the heat transfer mechanism in pipe-type cables, both analytical and experimental, to establish more accurate heat transfer coefficients
6. Investigation of the use of nonmetallic pipe for pipe-type cables to eliminate pipe losses. (Pipe losses are approximately 25% of the total losses for an uprated cable.)

The study also recommends that three modifications be applied to new pipe-type cable installations that will allow doubling of the rating by forced cooling. These are (1) the use of ASTM D1818–63 insulating oil, (2) using dual pothead terminations of presently available types, and (3) integration of presently available refrigeration units using reciprocating compressors and air-cooled condensers with the manhole installations.

7.4 Compressed Gas Insulated (CGI) Cable

7.4.1 Introduction

For the current and voltage levels needed to transmit large amounts of power underground, concentric metal tubes insulated by compressed gas, such as sulfur-hexafluoride (SF_6), appear to hold considerable promise. The compressed gas insulation has a dielectric constant of one, negligible dielectric losses, good heat transfer characteristics, and high thermal stability.[6] All of these characteristics are highly desirable in high voltage, high power cables.

The first installation of CGI cable is scheduled for completion in 1970 on the system of Consolidated Edison Company of New York.[7] This underground link is 600 feet in length and will carry up to 3,350 amperes at 345 kV (2000 MVA). This particular installation is the solution to a problem in which one 345-kV circuit has to cross four others in a substation. This should be considered a trial installation and will produce useful data to further the development of this type of cable. However, it should be noted that this is only a 600-foot length of cable, entirely on the property of the user. Considerable further testing will be necessary before it would be practical to consider installation of long lengths of this cable on public rights-of-way.

See footnote References, end of Chapter.

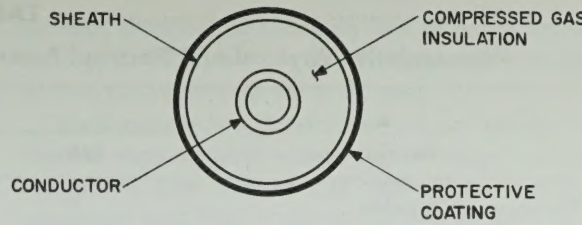


FIGURE 7.7.—CGI Transmission Line Conductor and Sheath.

7.4.2 Description

The conductor configuration for a compressed gas insulated cable is shown in Figure 7.7.[7] It consists of an aluminum, tubular, inner conductor supported in the center of a rigid tube sheath. High-strength aluminum with a protective outer coating is favored as the sheath material. The inner conductor is supported on insulating spacers, which, in the first commercial installation, are vacuum-cast epoxy disk insulators. The space between the inner conductor and outer sheath is filled with a pressurized insulating gas, sulfur hexafluoride (SF_6).

For three-phase power transmission, three single-phase concentric cables are installed side-by-side in a trench which is then filled with thermal backfill. This is shown in Figure 7.8.[7]

The inner conductor size, sheath size, and phase spacing will vary with voltage level and pressure of the insulating gas.[8] For the 345-kV CGI cable installed by the Consolidated Edison Company,[7] the aluminum inner conductor has an outside diameter (OD) of 152 mm (6 inches) and an inside diameter (ID) of 124 mm (4⅞ inches). The aluminum outer sheath has a 457 mm (18 inches) OD and a 445 mm (17½ inches) ID. The phase-to-phase spacing is 762 mm (2 feet 6 inches) in a trench that is 2286 mm (7 feet 6 inches) wide and 1220 mm (4 feet) deep.

While the exact physical and electrical parameters of future CGI transmission lines will vary with

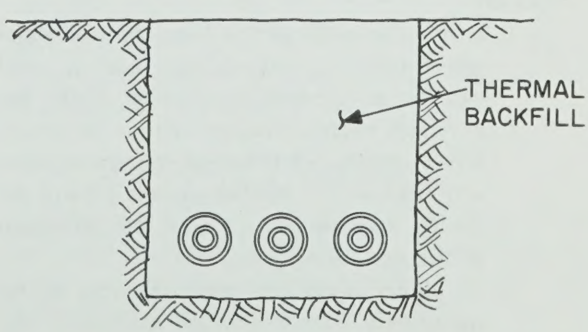


FIGURE 7.8.—Three-Phase CGI Transmission Line.

See footnote References, end of Chapter.

TABLE 7.1

Representative Physical and Electrical Parameters of CGI Transmission Lines Using SF_6 Gas

Parameters	Line voltage, KV				
	138	230	345	500	750
Conductor OD, inches	3	3	4	6	8
Sheath ID, inches	8	10	14	20	30
Peak gradient on conductor, kV/in	76	105	113	113	116
Peak gradient on sheath, kV/in	28.5	31.5	32.3	33.9	31.0
Capacitance, μF/mi	0.0913	0.0746	0.0716	0.0746	0.0678
Load current, amperes	1450	1530	2000	2870	3700
Power capability, MVA	347	610	1200	2500	4800
Charging Power, Mvar/mi	0.66	1.5	3.2	7.1	14.3
Critical length, miles	530	408	374	352	335
Losses, kW/mi	174	193	228	303	376
Phase separation, inches	16	20	28	48	60

particular design constraints, some proposed values are listed in Table 7.1.[8] These indicate the changes in the parameters as a function of voltage level in the range of 138 to 750 kV.

The selection of the operating pressure of the SF_6 gas is, of necessity, a compromise between liquefaction of the gas and desired dielectric strength.[7] The dielectric strength of the gas increases with increasing pressure, but the SF_6 liquefies at a higher temperature with increasing pressure. For example, SF_6 liquefies at $-16.7°$ C at 100 psi gauge, and at $-1°$ C at 170 psi gauge. It is possible to design a CGI cable to withstand a particular voltage level with either a large diameter enclosure and low gas pressure, or a smaller diameter enclosure with a high gas pressure. The advantages of high pressure, small diameter tubes are:

1. The size and cost of the trenching and backfilling operation is reduced
2. The smaller sizes of aluminum tubing with thick walls are more readily available in extruded form than large diameter, thin walled tubes.

The disadvantages of high pressure, small diameter tubes are:

1. It may be necessary to heat the cable system during periods of light load in cold weather to prevent liquefaction of the gas
2. For high current ratings, it may be necessary to force cool the cable system in some way because the smaller surface area of the sheath tube cannot transfer sufficient heat to the surrounding soil
3. At higher operating pressures (and correspondingly higher voltage gradients) the detrimental effects of free conducting particles are more likely to occur than at a lower gas pressure[6] and lower voltage gradient.

7.4.3 Advantages of CGI Cable

In those applications where high power, high voltage, underground power transmission is indicated, compressed gas insulated cable appears to offer the following principal advantages:

1. The charging current is greatly reduced because of (a) the unity dielectric constant of the insulating gas and (b) favorable electrode geometry
2. Dielectric losses are negligible
3. A greater ampacity, due in part to the superior heat transfer characteristics of SF_6. The other significant thermal characteristics are that (a) neither the compressed gas nor appropriately designed insulating spacers degrade thermally and that (b) the relatively large size of the sheath for each phase gives good heat transfer to the soil
4. The low charging current and the low dielectric losses, combined with the higher current-carrying capacity, result in a considerable increase in the critical length possible for the underground system.

In summary, there are a number of interrelated technical and economic problems that must be evaluated in the design of a CGI cable system. Nevertheless, there are enough attractive features to a CGI system to justify the present trial installations and continuing studies to further develop and optimize such a system.

See footnote References, end of Chapter.

See footnote References, end of Chapter.

7.5 Resistive Cryogenic Cables

7.5.1 Introduction

Another method of high voltage, high power, underground transmission that is receiving increased attention utilizes resistive cryogenic cables.[9–11] Resistive cryogenic cables operate at extremely low temperatures but above the superconducting range. In theory, advantage is taken of large reductions in the resistance of the conductor to increase line rating while avoiding the higher capital expenditure required for superconductivity. There are several competing designs that are under development and it is still too early to predict which may be reduced to practice first or which will prove to be the most economical in the long run. Present indications are that prototypes of two designs will have been built and tested by about 1974 or 1975. Assuming successful completion of these test programs, with no prohibitive problems being uncovered, resistive cryogenic cable systems might be available commercially about 1980.

7.5.2 Description

Conceptual designs for resistive cryogenic cables include one in which the cryogenic fluid (liquid hydrogen or liquid nitrogen) is used as an impregnant for a cable of conventional design using paper or synthetic tapes, another design in which the cryogenic fluid is the only insulation, and a design in which a vacuum is used as the insulating medium. In the first instance the cable is similar to conventional pipe-type cable and would be pulled into the pipe in long lengths and then both cable and pipe are filled with liquid hydrogen or nitrogen. These are classified as flexible cryogenic cables and proposed designs are shown in Figure 7.9(a) and (b). When the cryogenic fluid or a vacuum is used as the insulating medium, spacers are required to support the conductors within the containment pipe. These are classified as rigid cryogenic cables and are shown in Figure 7.9(c) and (d).

7.5.3 Future Research

Preliminary research carried out for the Electric Research Council Underground Transmission Committee,[9] indicates that the most probable candidate for successful deployment is the liquid nitrogen cooled, flexible cable shown in Figure 7.9(a). Technological and economic evaluations led to a current proposal to continue this research by installing a 1000-ft sample at the Waltz Mill test site as part of a three-year series of tests.

Another separate research effort has pursued a rigid cryogenic cable with a high voltage vacuum insulation. The designers of this system are also proposing to submit a sample for test at the Waltz Mill test site, with a test program that would carry over until 1974. Even if these tests should prove fully successful, it is doubtful if any significant commercial installations would be in service before the end of this decade.

See footnote References, end of Chapter.

7.6 Superconducting Power Cables

7.6.1 Introduction

Superconductivity refers to the phenomenon where the electrical resistivity suddenly disappears at low temperatures. In its application to power cables, it refers to operation at the temperature of liquid helium, in the range of 4° K. The appeal of superconducting cables is that losses in the cable can be reduced to practically zero (in the case of direct currents), or to a very low level (in the ac case), and thus virtually eliminate the heat dissipation problem. Also, superconductors can operate at unusually high current densities and consequently have very large power transfer capability of, say, up to 10,000 MVA at 345 kV.[12]

There are a number of problems that arise with superconducting cables beyond those of resistive cryogenic cables. Some of these are the ac losses in the superconductor and its dependence on temperature, current, and magnetic field strength. Heat transfer and thermal instability are also serious problems. Superconducting power cable research to date indicates that a continued research and development program is warranted. Such a program is estimated to cost about $8 million, exclusive of test facilities (the Waltz Mill site may be used for this purpose), and would extend over a period of 12 to 15 years.[12] It appears, therefore, that superconducting power cables will not be commercially applied before the late 1980's.

7.6.2 Description

There are several configurations that have been proposed for superconducting cable. Three of these, which are both representative and recent, are shown in Figure 7.10.[12]

See footnote References, end of Chapter.

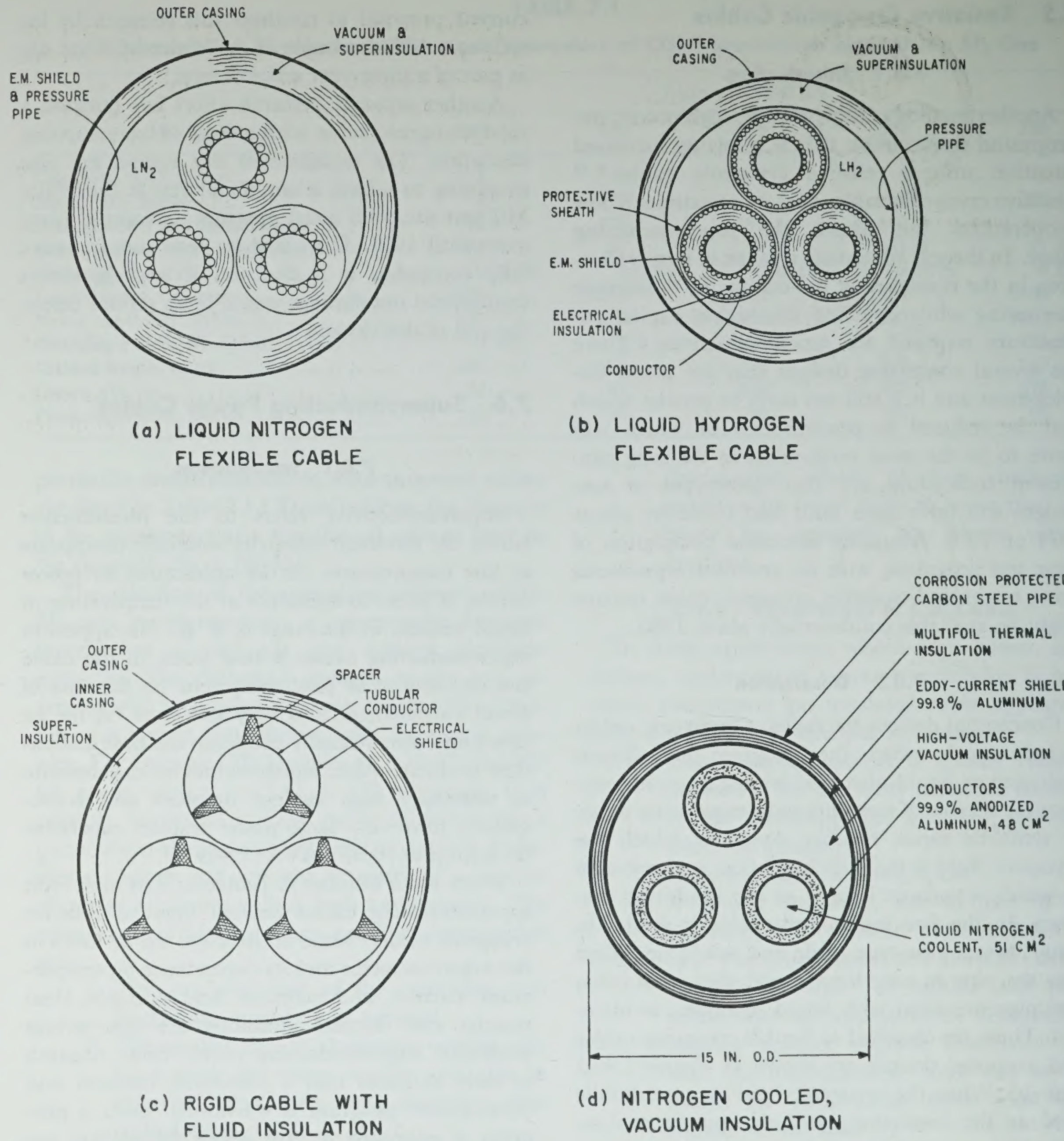


FIGURE 7.9.—Resistive Cryogenic Cables.

The general considerations in selecting the geometry of a superconducting cable are (1) it should be as compact as possible to minimize heat leak, material requirements, and induced electrical losses and (2) it must be large enough to satisfy the operating voltage and current requirements and to provide for adequate circulation of the liquid helium coolant.

The magnetically-induced electrical losses can be made zero by surrounding the active superconductors with a superconducting shield to confine the magnetic field. The dielectric losses are minimized by using a minimum number of solid supporting spacers and using the liquid helium as the only insulation.

The nature of superconductors is such that the current is confined to a thin surface layer, and thus only a small volume of material is required for the active conductor and the shield. This factor, material economy, and the desirability of low electrical stress dictate tubular configurations.

These general considerations result in the geo-

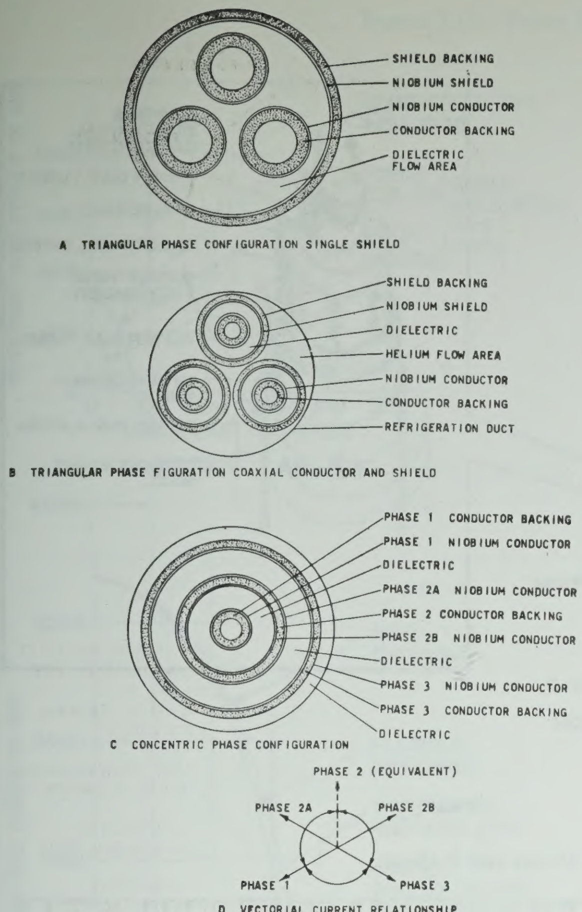


FIGURE 7.10.—Superconducting Ac Power Cable Configurations.

metrics of Figure 7.10, with niobium being used as the superconductor material. They differ principally in the methods used for electromagnetic shielding. In Figure 7.10.A, a single shield encloses all three-phase conductors, whereas each conductor is individually shielded in 7.10.B. The concentric phase configuration of 7.10.C requires no electromagnetic shield.

Niobium is the preferred material for ac power transmission because it has low losses and has the highest critical magnetic field of all the low loss superconductors. It has a critical field of approximately 1500 gauss (a level which, if exceeded, will cause the material to revert to an ohmic conductor with a high resistivity of 0.6×10^{-6} ohm-cm). However, the use of pure niobium as the only active conductor in a superconducting cable would be hazardous; in the event of an emergency causing it to switch to its normal state for even a few cycles, sufficient heat would be generated to damage the cable. To provide for such contingencies, some sort of stabilization is required. Two-layer stabilization requires electrodepositing the layer of niobium on a copper substrate. If the niobium reverts from the superconducting state, the copper becomes the preferred current path, and power transmission can be continued as long as the added heat can be removed by refrigeration. A more flexible scheme is three-layer stabilization. Here, a layer of niobium-titanium alloy would be placed between the layer of pure niobium and copper substrate. Then, if a high magnetic field switches the pure niobium to the normal state, the niobium-titanium layer which remains a superconductor will carry the current.[12] If the stabilization is done adequately, the niobium will recover its superconducting qualities and the cable will return to its normal operational state. As a point of interest, a typical superconducting cable would have values of parameters as follows:

$$C = 4.4 \times 10^{-11} \text{ farads/meter}$$
$$L = 2.52 \times 10^{-7} \text{ henries/meter}$$
$$R = 0.85 \times 10^{-10} \text{ ohms/meter.}$$

The terminals of a superconducting cable pose both electrical and thermal problems. The electrical problems arise because the high current superconductor must be operated at standard transmission voltages. The thermal problems stem from the large temperature differential, from near absolute zero to ambient, over a relatively short length of electrical conductor. A conceptual design of a terminal that has separate thermal and electrical grading sections is shown in Figure 7.11.[12] The thermal grading section would utilize vapor flow through the porous electrical conductor in the vertical riser to absorb the generated heat. It might also be possible to design a cryogenic pothead that would combine the thermal and electrical grading in one section. The design and development of actual terminals for superconducting cables is one of the areas requiring extensive research.

7.6.3 Economic Considerations

The probable cost of superconducting cable systems per MVA-mile varies considerably with power rating and voltage level. Some estimated costs, based on the best available information, are shown in Figure 7.12.[12] These curves indicate a lower transmission cost than present underground systems and point up the potential of superconducting cables for transmitting sufficiently large amounts of power. The cost of double-circuit systems depends strongly on the magnetic field level and the reliability demanded of the circuit. Thus, curve B in Figure 7.12, which demands 100% rated capacity with one circuit down, is considerably more

See footnote References, end of Chapter.

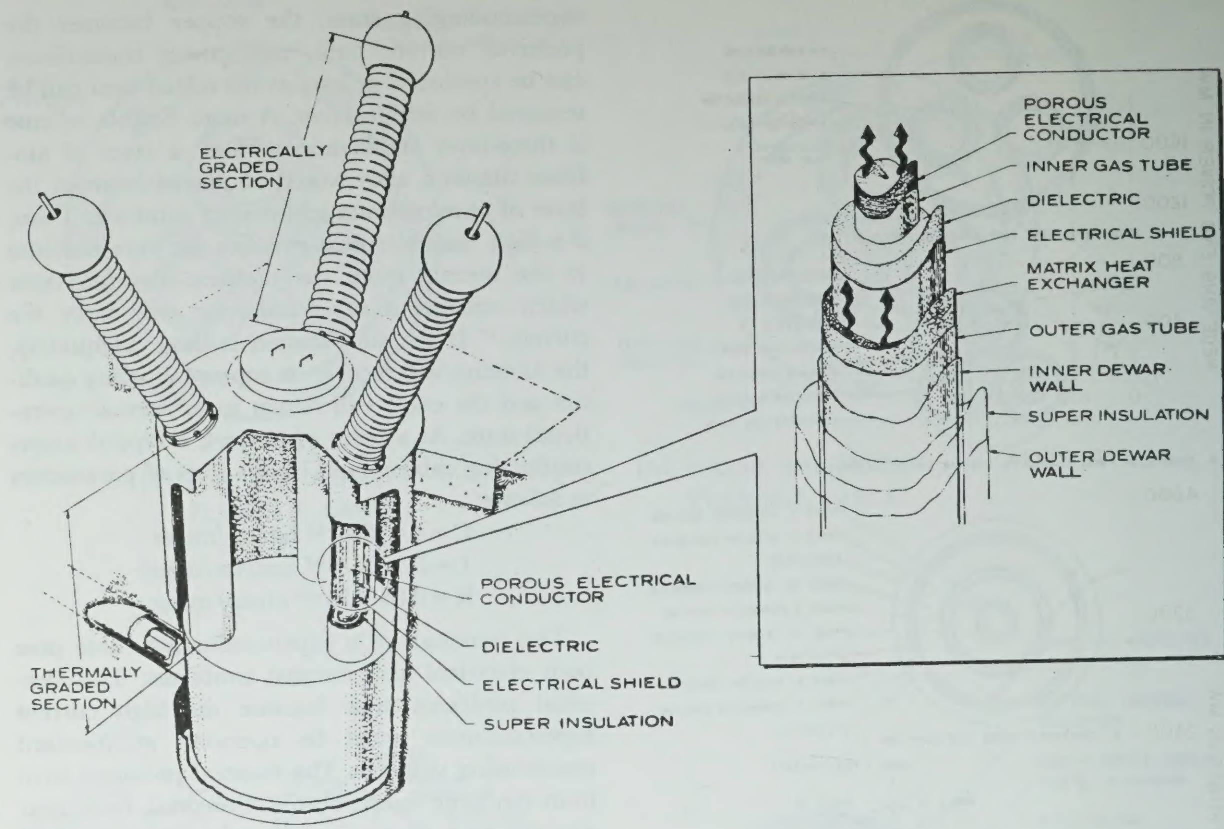


FIGURE 7.11.—Terminal Dewar and Potheads.

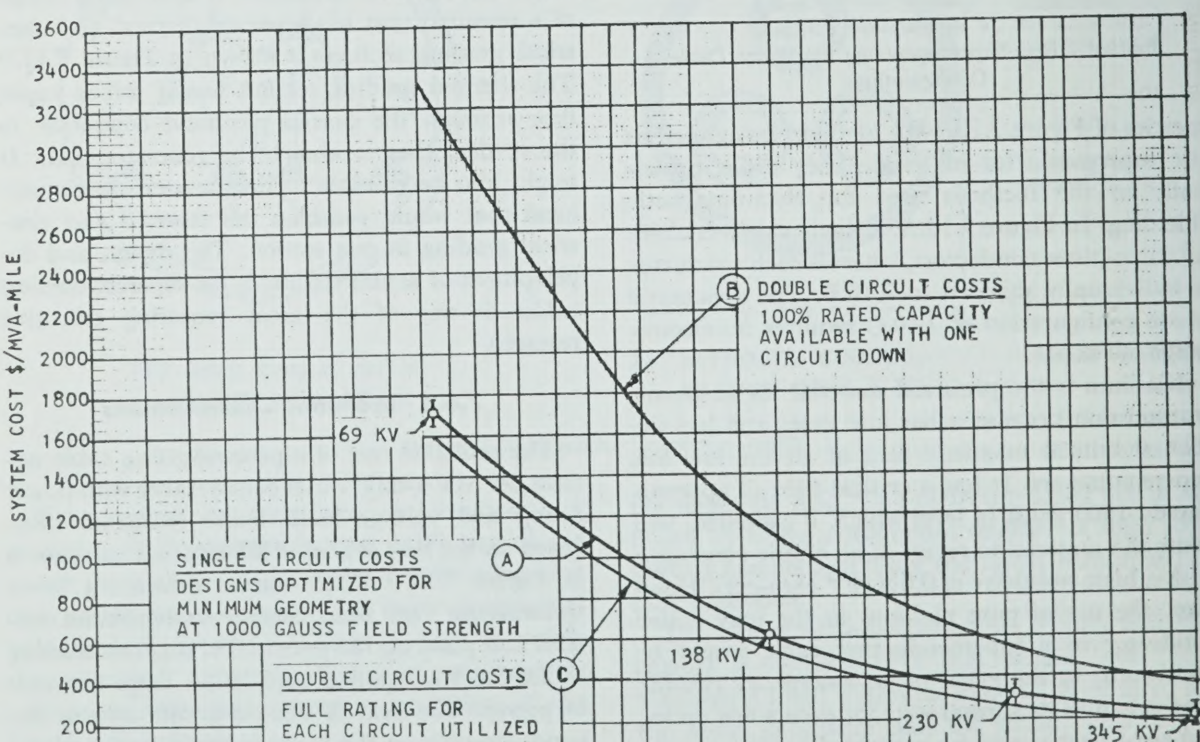
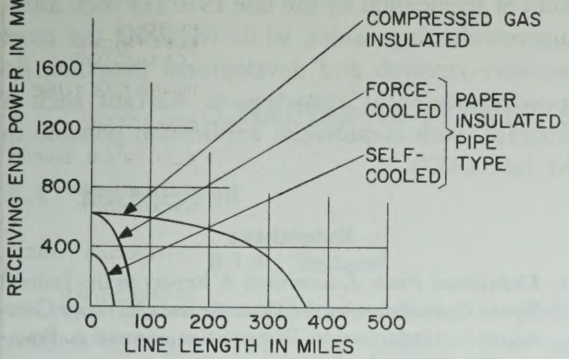
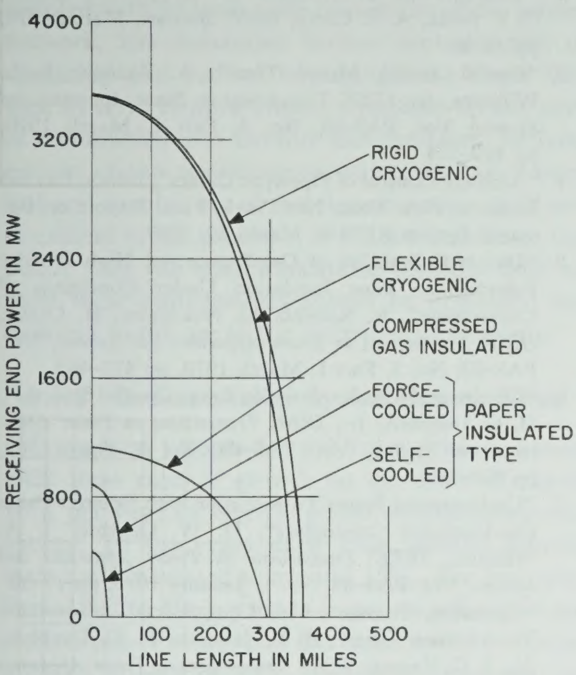


FIGURE 7.12. Single and Double Circuit Superconducting Cable System Costs.

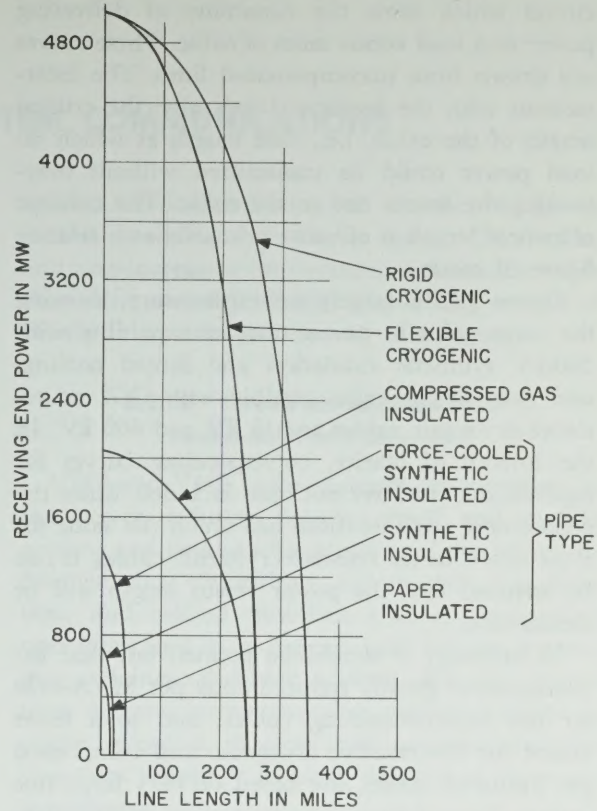
FIGURE 7.13.—Power Delivered vs Line Length.



A. 230KV CABLES



B. 345KV CABLES



C. 500KV CABLES

costly than curve C, which assumes that power could be routed through other parts of the transmission network if one circuit were out of service. The double circuit costs in Figure 7.12 assume independent refrigeration systems for each circuit; these costs might be reduced if refrigeration were used jointly.

As previously mentioned, the magnetic field strength at the conductor surface is an important limiting factor in superconducting cables. The conductor surface field, in turn, depends upon the shield diameter, decreasing with increasing physical size. These factors are the basis for correlation between system costs and a design value of field strength.[12] Related to this is the need to design a factor of safety into the cable system so that currents larger than rated (due to a system fault, say) will not cause field strengths in excess of the critical value, with consequent reversion to normalcy of the superconductor. The designs of Figure 7.12 are optimized in this respect.

See footnote References, end of Chapter.

7.7 Comparison of Underground Transmission Methods

The economic and technical data for pipe-type cables in the 69-kV to 500-kV classes are well detailed in the previous report to the Federal Power Commission on Underground Power Transmission.[1] An attempt will be made in this section to compare the new and proposed methods of underground cable systems that have been discussed in this chapter.

At the outset of this discussion, it is important to bear in mind that the economic and technical data are approximate. The data are based on limited information and do not yet come from the realm of engineering practice. The data which are presented can form the basis for relative evaluation of the various methods, however, and should be viewed in this light.

See footnote References, end of Chapter.

With the preceding qualifications, the comparisons are presented in Figure 7.13 in the form of curves which show the capability of delivering power to a load versus miles of cable. These curves are drawn from uncompensated lines. The intersections with the horizontal axis give the critical length of the cable, i.e., that length at which no load power could be transmitted without overloading the source end of the cable. The concept of critical length is of value primarily as a relative figure of merit.

Figure 7.13 is largely self-explanatory, showing the large gains in power transfer capability with 500-kV synthetic insulation and forced cooling, and even larger gains possible with CGI or resistive cryogenic cables at 345 kV and 500 kV. In the interest of clarity, corresponding curves for superconductors have not been included. Since the geometrical considerations are much the same for these cables as for resistive cryogenic cables, it can be assumed that the power versus length will be similar also.

In summary it should be pointed out that expectations of greatly reduced costs per MVA-mile for the superconducting cables, and to a lesser extent for the resistive cryogenic and compressed gas insulated cables, are based on very large line ratings. Even if these systems were available today, there would be few systems that could utilize cable lines with ratings in the 3,500 mva to 10,000 mva range. The projected economy of these systems is, of course, not available on today's requirements for lines with capacities of 1,000 to 1,500 mva.

7.8 Conclusions

The evaluation of present and future possibilities for improving underground power transmission capabilities can only be described as encouraging. The technology is available to uprate new installations of pipe-type cables through forced cooling, and compressed-gas-insulated cable technology has come to commercial realization to increase underground power transfer. It is expected that further refinements in each of these methods will produce further benefits.

Resistive cryogenic cables offer great promise from both an economic and capability standpoint and have the possibility of being developed to the point of application by the late 1970's or soon after. Superconducting cables, while requiring the most extensive research and development program, do appear sufficiently attractive to warrant such a program, with commercial application possible in the late 1980's.

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CHAPTER 8. POWER SYSTEM COMMUNICATIONS

8.1 Background

8.1.1 General

Communications requirements of electric power systems have grown at an increasingly rapid rate over the past decade. The rapid load growth, coupled with an increasing complexity of the power network, has demanded further centralization of operating and control responsibilities. These factors, in turn, require utmost reliability on the part of communications circuits and facilities. In fact, certain of the requirements which deal with control and monitoring of the electric system itself are so critical to the provision of reliable service to the public that the communications facilities used to meet these requirements should be dedicated exclusively to the use of the electric utility system.[1]

8.1.2 Communication System Growth Rates

Long-term records for the years prior to about 1952 show rates of growth on the order of about 10% per year for electric power system communications. In the years since 1952, annual growth rates have increased to around 15%. For example, from 1966 to 1967, private microwave facilities by electric power companies increased by 5,364 route-miles, a growth of 20%. Trends such as this are expected to continue.

8.2 Functions of Utility Communications Facilities

8.2.1 Voice Communications

8.2.1.1 Point-to-Point

Electric utilities require fixed point-to-point communication services for the "dispatch" class of circuits. Such channels are essential for close coordination between parties responsible for overall system operation and those having immediate and individual responsibilities for the generation, transmission, and distribution of electric energy to customers within a particular system. Of similar, and ever-increasing importance, are needs for voice channels between the major dispatching centers of closely interconnected electric utility systems.

8.2.1.2 Fixed Point-to-Mobile and Mobile-to-Mobile Services

UHF and VHF radio channels are necessary in the power industry between fixed and mobile stations and between the mobile stations for maintenance crew dispatching, construction coordination, and related functions vital to day-to-day operations and to emergency and service restoration activities of electric utilities. All such operations demand interference-free communications to assure reception of clear and uninterrupted instructions necessary to avoid delayed or incorrect operations.

Additional uses of mobile radio frequencies are permitted under certain conditions and special circumstances. For example, tone or impulse signaling at these frequencies makes possible the automatic indication of failure of power system equipment or the indication of abnormal conditions, which, if not promptly corrected, could result in failure of equipment.

8.2.2 Telemetry

The encoding, transmission, and remote display of meter readings are essential to the centralized surveillance and control of extensive generation and transmission facilities.

8.2.3 Control

Communications channels are widely used for control of electric generation in such primary functions as load frequency control, economic dispatch, and other recognized forms of generation allocation. Such functions are most often carried out by incremental pulsing and "raise-hold-lower" types of signals.

Related to the load frequency and generation

See footnote References, end of Chapter.

scheduling control is the remote supervisory control of plant and station devices from centralized control offices. Operations are normally in the form of "off-on", "start-stop", "open-close", or similar two-state coding.

8.2.4 Protective Relaying

Protective relaying of a power system is in many vital ways dependent upon the sampling of instantaneous information at different points in the electric network—often points separated by many miles. The "pilot relay" and "transferred tripping" schemes are illustrations of relaying methods that utilize communication channels for the transfer of the necessary information. "Trip", "block trip", "guard", and "permit trip" are typical of the signals transmitted.

8.2.5 Status Monitoring and Alarming

Communications channels find increasing application in the monitoring of abnormal conditions in electric plant and station equipment. Timely indication of failures or marginal operations can often permit correction of difficulties before they result in any service outage. Accurate indications of trouble sequence and locations aid in rapid restoration of service after outages due to storms.

8.2.6 Transmission of Graphic Data

Increasing applications are being made of both private and common carrier facilities for the transmission of graphic information. Teletype facilities have been in use for some time for transmission of system control data and records. Further use can be made of facsimile equipment to transmit printed material, drawings, photographs, etc.

8.2.7 Special Functions

Increased use of electronic computers has led to the requirement that transmitted data be digitally encoded and suitable for direct input to computer peripheral devices and to computer core storage as well. The most critical of these applications are those for power system control, monitoring, and evaluation.

Important functions of engineering and system planning are also being served. Communication of data for stores records, job scheduling, and general financial and accounting transactions are other valuable contributions to efficient utility operations.

8.3 Types of Available Communications Facilities

8.3.1 Microwave Transmission

Since about 1950, point-to-point microwave radio (952 MHz and above) has proven to be a valuable and versatile tool in the operation and control of electric power systems.

A major advantage of microwave radio is its wideband frequency capability which permits transmission of amounts and types of information which are either technically unfeasible or economically unrealistic with other methods. In accordance with Federal Communications Commission (FCC) regulations, information-carrying capability of a microwave channel is limited to the equivalence of 300 telephone (voice-grade) channels. Multiples and divisions of these voice channels are possible for other forms of information transmission as required by a particular power system or operations area.

The reduced exposure of microwave facilities to natural and man-caused hazards makes it highly reliable under both normal and emergency conditions. Microwave terminal and repeater installations are concentrated at relatively few locations typically separated from one another by distances on the order of 25 miles. This is in contrast with the continuous exposure of wire-line types of communications systems.

8.3.2 VHF-UHF Radio

Radio channels in the very-high (37 to 158 MHz) and ultra-high (451–467 MHz) frequency portions of the spectrum are extensively used for communications contact between service dispatching centers and radio-equipped vehicles. Availability of portable units permits flexible communications among base stations, mobile units, and hand-carried units.

8.3.3 Power Line Carrier

Transmission of low-frequency signals (approximately 40 to 220 kHz) over power transmission line conductors is a commonly used method of information transmission within an electric power system. The extra equipment necessary to create a communications channel on the power line is relatively simple and trouble-free, but the limited bandwidth capability also limits the amounts and types of information that can be transmitted. Where only one or a few channels are required over moderate distances, however, power line carrier represents

an economical and reliable solution to communications needs.

Cost factors come increasingly into play in EHV systems because of insulation requirements. Coupling capacitors and blocking filters (line traps) become large and expensive items of equipment. Recently developed techniques for using insulated overhead ground wires to transmit carrier-current signals offer attractive possibilities. In addition to cost advantages resulting from reduced insulation requirements, other possible advantages include the ability to use lower frequencies than can efficiently be propagated through phase conductors and the ability to provide channels with lower background noise for given transmitter power. Other problems remain, however, and additional work is required before these techniques can be universally applied.

8.3.4 Common Carrier Facilities

Leased telephone lines are often used for bulk, general purpose communications requirements in an urban area or between urban areas. Increased reliability can be obtained from duplicate circuits on isolated routes. Individual leased circuits find application as tributary circuits or feeders to a private microwave system.

8.3.5 Private Telephone Facilities

Pilot wire circuits or cables, installed along distribution and subtransmission rights-of-way, are sometimes used for pilot relaying, control, alarm, telemetering, and, less frequently, for voice communications. Pilot cables and other private telephone facilities are seldom used for long distances or high densities of channels because the quality is low.

8.4 Future Considerations

8.4.1 Intra-system Needs

The trends to larger generating stations remote from load areas and the development of bulk power transmission corridors will force a rapid increase in intra-system telemetry, control, monitoring, and protective relaying needs.

The increasing complexity of the power system will demand the ability for efficiently linking all presently available types of communications, both privately supplied and leased, in order to gather essential data from all diverse points with the required reliability and speed.

8.4.2 Inter-system Needs

Major growth is expected in communications facilities required for inter-system control and operation of interconnected power systems. Many more long-distance circuits of all types will be required for rapid and secure exchange of information on a regional and inter-regional basis to maximize the reliability of bulk power systems through status monitoring, evaluation, and simulation methods. It is anticipated that such operations will be increasingly based on automatic data processing techniques.

Fullest possible freedom for integration of all present types and forms of communications methods will be most essential to the fulfillment of these needs.

8.4.3 Anticipated New Functions and Applications

The following are among the new and more fully implemented functions of presently available types of communications to be expected:

1. Further advances in real-time acquisition and transmission of information and the return of action-inducing signals between fixed points
2. Mobile and portable teletype or facsimile operation for unambiguous display of operating orders and various other types of graphic information
3. Further application of television techniques for surveillance of power system devices or their instrumentation.

8.4.4 Anticipated Developments in Equipment and Techniques

8.4.4.1 Digitized Signaling

Rapid advances are expected in conversion from analog-to-digital signaling methods. Application of decision theory, adaptive techniques, and advanced coding methods can be expected to result in improved communications accuracy, reliability, and security.

Inherent in these changes will be a transition from amplitude modulation (AM) methods and frequency division multiplexing (FDM) systems to pulse methods and pulse-code modulation (PCM) techniques.[2] The basic advantages of PCM in overcoming the effect of noise and interference,[3] coupled with capabilities for using powerful error-detecting

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See footnote References, end of Chapter.

codes (and ultimately error-correcting codes) are expected to find wide usage in electric power system communications provided that a sufficient radio frequency spectrum can be allocated to these needs.

PCM techniques are being rapidly implemented by communications common carriers. Similar transition by electric utilities can be expected as advances and economies are made in integrated-circuit and solid-state devices and as spectrum-allocation problems are resolved.

Digital methods are expected to be applied to all functions, including voice communications, but will be particularly adaptable to computer-based electric system telemetering, monitoring, control, and real-time simulation.

8.4.4.2 Automatic Communications Path Selection

Further standardization of communications terminal devices and channel equipment is expected to result in increased reliability and flexibility of critical channels. It becomes increasingly necessary that alternate routes be available for maximum reliability and security of essential communications services. Additional standardization of equipment and techniques is necesssry so that alternate communications media can be employed as well as alternate geographic routes.

8.4.4.3 Direct Long-Distance VHF Radio Channels

In order to serve the growing power system intercommunications needs set forth earlier in this chapter, it is expected that techniques will be established and equipment developed, as necessary, for direct, nonrepeater radio channels between major power control centers.

These techniques are deemed necessary for maximum reliability over long distances and backup of private microwave facilities and common carrier circuits. Frequencies now allocated to the Power Radio Service do not permit communications over the long-distance ranges. Implementation of these plans is contingent upon approval of the FCC.[3]

8.4.4.4 High-Frequency Coaxial Cable Systems

It is reasonable to expect that future use will be made of coaxial cable transmission for multichannel services or broad-band data signals. It is probable that such facilities will share power transmission rights-of-way and will, in this sense, be an extension of pilot cable, power line carrier, and insulated groundwire techniques.

8.4.4.5 Waveguide Transmission Systems

It is possible that, in the long-range future, use will be made of wave-guide or other "controlled environment" systems for movement of mass blocks of information. Unless there is a major breakthrough in the state-of-the-art, it is assumed that economic considerations would limit privately-owned applications to short distances. The same comments would apply to the extension of these techniques to the visible light portions of the spectrum (lasers). While private ownership and operation of such facilities is unlikely, circuits supplied by common carriers may well use such facilities for portions of a route.

8.4.4.6 Satellite Communications

Use of satellite communications channels may be made in the medium-to-long-range future so as to meet continuous needs for large numbers of channels between discrete points.

It is not very likely that use of separate facilities dedicated exclusively to electric power system needs would be feasible even on the basis of cost-sharing among a number of systems.[4] Circuits may well be leased, however, for isolated applications, dependent upon the establishment of one or more, synchronous satellites for intra-continental common carrier traffic.

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CHAPTER 9. ADVANCED CONTROL AND DISPATCH

9.1 Background

From the viewpoint of control theory, a power system can be looked upon as a large, complex, geographically widespread, constantly changing system. Several levels of control are required to operate such an interconnected power system. The term "local control" refers here to any of the many diverse controllers which initiate action at local stations based on information obtained locally. It includes such controllers as governors, voltage regulators, combustion controls, and protective relays. The next level of control is "area control" which includes supervisory control of several stations and future area-oriented control and data handling. The term "central control system" is used in this discussion to denote the central dispatch and control system that exercises higher level control over the entire power system. A central control system receives data from various remote points on the power system and uses this information to provide overall coordinating control. It is the prime subject of this discussion. The term "regional control system" denotes a still higher level of control over several central control systems in some specified region.

The central control system has evolved from manual control based on an operator's observations to the present-day, complex, computer control. This control system considers system frequency, power flow on interconnections, and the economics of generating and transmitting electrical energy. Most large power systems in the United States installed analog control computers to exercise largely automatic control over the minute-to-minute generation on the system. In many cases, the large-scale digital computer has replaced the analog computer primarily because of greater flexibility in meeting changing system conditions. The digital computer can also be used in a multi-functional control mode. As an example, a load frequency control program could be interrupted by an emergency control program in the event of a serious system contingency.

9.2 Central Control System Functions

Present-day central control systems perform many functions automatically in conjunction with local and area controls, leaving the system operator free to deal with special situations. While present methods and concepts of control are changing very rapidly, the functions automatically performed by a modern central control system are—

1. *To gather system information, process it, and display it in various ways for the guidance of the system operator.*—This information normally includes real and reactive power output of generating stations, power flow on ties to other systems, power flow on key transmission facilities, frequency readings at one or several locations on the system, selected circuit breaker and switch positions, and notice of operating changes.
2. *To maintain maximum system security.*—The automatic controls normally provide information for the guidance of the operators. If a facility is switched out because of a failure, indication would be given in the operator's control room. The information could also include warnings of facilities heavily loaded or which would be overloaded if certain contingencies occurred. The system operator then assesses the security of the power system based on past operating experience and the results of off-line studies.
3. *To adjust generation to satisfy the power requirements of system load*—To do this it is necessary that enough units be running with their auxiliaries, that governors be set to admit the proper amount of steam (or water) to the turbine, and that "load frequency control" sense frequency, tie line loading deviations from normal, and adjust the governor "set points".
4. *To minimize the overall cost of generating and transmitting electrical energy to the total system loads.*—This is done by making control

decisions based on the cost of fuel or water, efficiency of the generating units and consideration of transmission losses. The cost of power available from or salable to other systems must also be included.

During abnormal system operation, the control system should function to restore normal operations as quickly as possible.

9.3 Future Considerations

9.3.1 General

Methods and concepts of power system control can be expected to change considerably in the next 10 to 20 years due to digital computers and data transmission techniques. Some fundamental factors that will affect the rate and extent of this change are—

1. The availability of reliable computing equipment with the speed and memory capability required to handle large power system problems, and the availability of adequate inter-computer communication
2. The rate and extent of progress in the development of sensing devices and communication facilities, as well as new techniques for information displays
3. Development of new and increasingly complex analytical techniques and the associated application programs required for the solution of operating problems to be handled by the control system. This includes the development of accurate dynamic mathematical simulations of generating plants and their elements, transmission systems, and loads. Without these, the development of analytical techniques cannot be adequately related to actual system problems.
4. Availability of computer programming required for the operation of either real-time or time-shared computing systems, including the necessary data-handling capabilities
5. Availability of trained personnel required for the computing system design, programming, testing, and maintaining of an effective control computer installation.

9.3.2 Local Controls

9.3.2.1 Power Plants

It appears that within the next two decades each new thermal power generation plant will be automatically controlled by a plant operator working with a digital computer, on site. The man-computer interface will be developed for efficient two-way communication. Some modern hydro plants are now operated by remote, computer-directed control, and this trend will continue.

In the case of the local power plant control computer, the computer would receive data from power plant sensors which measure quantities such as electric power output, voltage, water flow, steam temperature, etc. It would process this information into a form which can be used by the plant operator and by the control program in the computer. The plant computer would also condense the information into a form suitable for transmission to the central control system. In addition to the directly metered data, the power plant computer would receive data inputs from the power plant operator and from the central control system.

The local power plant computer could also be used for event recordings, power plant tests, and various data recording tasks.

9.3.2.2 Switching Stations

During the next one or two decades, some of the major switching stations on the EHV transmission network may become automatically controlled by a special-purpose digital computer located at the station. The switching station control computer would have various control programs available. The choice of which program to use would depend on system conditions. As with the power plant control computer, the switching station control computer could act independently of the central control system. However, the central control system would often furnish information to the local switching station computer in the form of goals or criteria which specify the performance that is desired.

The switching station control computer would also perform event recordings such as oscillographic recordings of faults and other disturbances, automatic testing of equipment such as relays and circuit breaker controls, and various data recording tasks.

9.3.3 Central Controls

9.3.3.1 General

Future trends in the development of central control of power systems will be greatly affected

by the relative roles assigned to sophisticated controls and to system strength in designing a reliable power system. If a system is strong enough, relatively simple controls can be used. If sophisticated controls can be made to operate satisfactorily, the same system reliability could, in some instances, be obtained in spite of some reduction in system strength. The selection of proper balance between system strength and control will remain an area of system planning judgment and economic analysis. The introduction of sophisticated control schemes will undoubtedly be gradual, for system security reasons, and may involve a period when the new control schemes operate in parallel with well-known standby controls.

Power systems require several levels of control. The transfer of some control functions to a higher level is feasible and may be desirable. One advantage of centralizing control decisions by moving them to a higher level is the fact that the higher level receives information from a much broader segment of the overall power system. Hence, the higher level has potential for more capability to make decisions that are optimum from the overall system standpoint. Another advantage of centralization is that it can be more efficient.

There are also several serious disadvantages to centralization, however. The cost associated with the needed communications can be very large. Central control also is less reliable, not only because of possible breakdown of the communication links, but also because it is more subject to catastrophic failure when the centralized system itself becomes inoperative or errs in "judgment". Another disadvantage of centralization to higher levels of control lies in the fact that such levels usually have less detailed information on local conditions. A local controller can provide better control of local equipment since it "knows" the equipment better.

These preceding factors seem to point to the need for control "hierarchies" in which certain functions are assigned to specific control levels.[1,2] There will also be a need for standby control and protection at the various levels of control.

9.3.3.2 Man-Computer Interface

It is anticipated that increasingly large amounts of information could be furnished to the system operator by computer-driven displays which would present the material in different forms, depending upon which is most appropriate; for example, numbers, plots and graphs, network diagrams with color-coded flows, switching diagrams with open breakers color coded, etc. The operator would communicate with the computer using sophisticated input devices which are simple to operate, such as function keyboards, light pens, etc. The computer would have an extensive software system so that a conversation mode of communication between operator and computer could be maintained.

A rapidly-growing display concept is that the system operator should be shown whatever he needs to know, as determined by the computer and by his own requests. Thus, any quantities which have experienced sudden changes, or which are approaching limits, will be displayed automatically.

9.3.3.3 Information Gathering and Processing

Although the future will see the digital computer being used as an information processing and analysis device, it will also function as an actual control device and as a dispatcher assisting device. Large percentages of computer time will be spent on processing raw data gathered from meters and other sources to extract the pertinent information and convert the information into a form which is most useful to other computer algorithms and to the system operator. Computers will release operators from taking so many handwritten readings.

9.3.3.4 Security Assessment

Another large percentage of computer time will be devoted to analyzing the data (security assessment) and to performing analyses as requested by the system operator. The analyses will be used by the operator to help him make his decisions. Thus, the importance of the human operator in certain overall control decisions is likely to increase. He will spend less time on routine functions and more on making higher level judgments. A digital computer is a very fast, reliable, efficient tool for doing routine, well-defined tasks. However, a digital computer can handle an unexpected situation only if the man who programmed the computer expected the unexpected and built in the appropriate logic. In situations like this, the human operator is still the best decision maker available.

9.3.4 Regional Control

The regional control system of the future would provide "control" over regions containing many

See footnote References, end of Chapter.

utilities (or pools), each with its own central control system. The regional control system would be similar to a central control system in the sense of the role of human operator, computer, and computer-driven displays. However, the regional control system can be expected to act primarily as an "information clearing house" which facilitates information exchange between the various central control systems in the region. Each central control system would send a summary of its system's status to the regional control system and would receive in return only the particular information about the other systems that it requests. The regional control system would also provide some security assessment functions such as—

1. Monitoring total available spinning reserve in the region
2. Evaluating effects of inter-system power sales on overall region network flow
3. Monitoring maintenance schedules.

9.3.5 Research on Control Systems

Increasingly extensive research effort on the application of advanced control system concepts to electric power systems is in progress. Over the last several years, a number of technical papers has been published on this subject. It appears that the application of advanced control systems would require the use of some type of hierarchical control[1,2] and that this, in turn, will require extensive input information on the "state" of the interconnected power systems. Research is now in progress to develop various techniques to obtain such information.[3-10]

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CHAPTER 10. TESTING FACILITIES

10.1 Introduction

As power systems continue to grow in voltage level and capacity, facilities for developmental testing of new equipment and proof testing of manufactured equipment must be expanded to meet the new requirements. There is increasing evidence that it is neither satisfactory nor economical merely to extrapolate existing proof testing requirements to the new voltage and capacity levels. It is no longer adequate to isolate the test requirements for individual pieces of equipment from the conditions on actual systems. For example, the test requirements for circuit breakers are vitally influenced by the behavior of surges existing of the power system, and the surges are in turn generated by the equipment that is to be tested. Therefore, at least in the area of development testing, it is becoming essential to provide testing facilities having all the characteristics of operating systems.

The use of synthetic testing methods is already widespread, and without such methods it would not be possible to verify the adequacy of equipment now being manufactured. However, these methods depend upon assumptions regarding the validity of the synthetic procedures that need to be verified by corresponding tests under actual system conditions. As capacities increase, the extrapolation needed from the synthetic circuits becomes greater, and the verification or modification of these methods must be amply demonstrated.

10.2 Needs of the Industry

10.2.1 Switchgear Testing

In the development of switchgear, the phenomenon of the short-line fault must be adequately covered in tests on the circuit breakers. The effect of system characteristics on switching surges, and the effects of these voltages on interrupting performance, must also be evaluated under realistic conditions.

10.2.2 Equipment Insulation Evaluation

In the evaluation of insulation, similar interactions must be simulated in the test facilities, particularly because, at the higher voltages, switching surges, rather than lightning, are becoming the critical limitations and are the result of the interaction between the equipment and the system. Therefore, in looking toward the future, more complex and comprehensive testing facilities, involving full system characteristics, must be available.

10.2.3 Air Insulation Systems Testing

Testing facilities also have to be augmented in the high voltage field where knowledge of insulation characteristics of air must be extended to much higher voltages. The increasing importance of contamination dictates more extensive facilities that can study this problem under a wider variety of conditions and can develop means for minimizing the effects.

10.2.4 Conductor Considerations

As larger and larger currents are required, further studies are needed of conductor heating and current-carrying capacity, as well as of magnetic interactions, to current values beyond those now in use.

10.3 Present Testing Facilities

10.3.1 High Power Laboratories and High Voltage Laboratories

At present there are several high voltage laboratories but only a very few high power laboratories available in the United States for testing large circuit breakers and other components for maximum interrupting duty. However, there are several high power laboratories outside the U.S. used by American manufacturers.

10.3.2 Testing Facilities of Operating Utilities

Certain utilities are active in performing tests on their systems but fault tests are primarily on lower voltage equipment. Several utilities have mobile instrumentation trailers that are used on system tests to verify equipment performance and obtain data on switching surges and other system characteristics.

10.4 Future Testing and Research Facilities

The developmental work of the future will involve so many unknowns that new designs will have to be based on empirical information from laboratory tests rather than extrapolated theory. This laboratory testing must be carefully done, and several test facilities will have to be used to compare techniques, consider different weather patterns, etc.

To meet the requirements of future testing programs, equipment is required for higher voltages and currents than is presently available. The cost of such equipment is so great that many future laboratories will be sponsored jointly by several organizations having interests in the problems being investigated. Such joint efforts have been very successful in the past. Present examples include ultra-high-voltage research projects sponsored by the Electric Research Council in the area of overhead, ultra-high-voltage transmission at the General Electric Company's facility near Pittsfield, Massachusetts, and in the area of underground, extra-high-voltage and ultra-high-voltage transmission at the Westinghouse Electric Corporation's facility near Waltz Mill, Pennsylvania. Another example is the ultra-high-voltage research project being undertaken jointly by the American Electric Power System, ASEA of Sweden, and The Ohio Brass Company of Mansfield, Ohio. An electric power research and development facility near Grand Coulee is under consideration by the Electric Research Council. It is expected that more such joint ventures will be required to meet the needs of the future at reasonable cost. One of the major problems associated with joint testing facilities will be the difficulty of using them for developmental testing of company product lines by individual manufacturers. It does appear that considerable effort should be devoted to the resolution of this aspect of future joint test facilities.

Large testing facilities will provide for excellent training of specialized personnel. Opportunities will exist for cooperation with universities so that research work at such a facility can be incorporated into graduate programs. The association of problems-oriented personnel from industry and theoretically-oriented personnel from the universities should be of mutual benefit.

All of these interactions suggest that the early development of such facilities should be pursued.

CHAPTER 11. ANALYTICAL TOOLS AND APPLICATIONS

11.1 Introduction

Modern analytical tools play a vital role in the area of electric power systems engineering, just as they do in many other areas of science and technology. Such tools serve as indispensable aids in arriving at an informed engineering judgment. The electric utility industry has been for many years an eager user of the most advanced analytical tools available and must continue to do so in the future to assure the maximum possible reliability and economy of electric service. This chapter contains a brief survey of various analytical tools that are available to the industry, a discussion of their relative merits, and an appraisal of the future trends in their development and use.

Modern analytical tools used in electric power systems engineering invariably call for formulation of a "model" of the power system. The accuracy with which such a model corresponds to the actual system must be compatible with the required accuracy of the answers being sought by the analysis.

11.2 Description of Analytical Tools

11.2.1 System Modeling

System models fall usually into two basic categories: mathematical and physical. In order to simulate successfully an actual system, a model must be capable of yielding, in a scaled down form, a response to a given input which is the same as the response of the actual system to a scaled input of the same form.

A model which can simulate a system for all possible inputs is almost never achievable because the response of a system to one class of inputs is determined by certain system parameters and is usually unaffected by other parameters which may be determining for another class of inputs. Simplifying assumptions are therefore necessary in the modeling process so as to incorporate in the model the simulation of those system parameters which are relevant to the class of inputs and responses being studied. Consequently, a system almost never is simulated by a needlessly complex overall model but rather by a number of simplified models. The choice of model is determined by the type of problem being analyzed and requires exercise of considerable judgment by the investigator to balance accuracy with cost.

Modern analytical tools used in the analysis of system models can be classified in the following general categories:

Digital computers
Electronic differential analyzers
Miniature replicas

The first two types are designed to use mathematical system models while the last consists of physical models.

11.2.2 Digital Computers

Digital computers constitute the most widely used and the most rapidly advancing analytical tool today. In their application, a mathematical model of a system is formed by a set of equations which describe the relationships between the input, the system parameters, and the system response.

A digital computer is capable of performing only the four basic arithmetic operations of addition, subtraction, multiplication, and division and therefore can evaluate differential equations, trigonometric functions, exponentials, and the like only in finite steps. A solution for any problem must therefore be obtained by numerical and logical techniques that employ the four basic operations.[1]

Digital computers are all organized along similar lines[2] and include the following basic elements whose interrelation is shown in Figure 11.1.

1. *Input Unit.*—This equipment accepts information from the "world outside the computer" in the form of punched cards, punched paper tape, magnetic tape, special keyboards or switches.
2. *Control Unit.*—This equipment translates

See footnote References, end of Chapter.

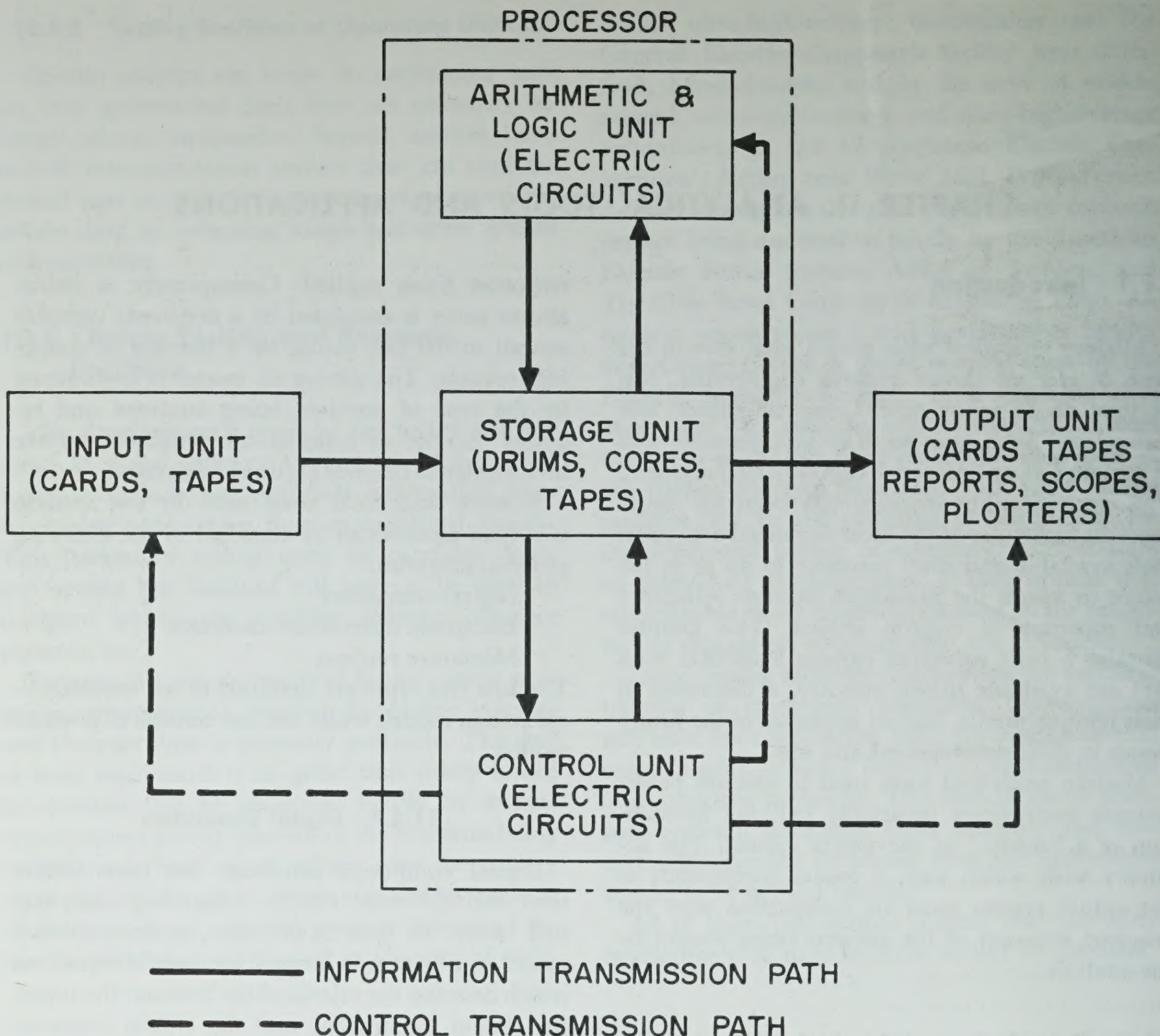

FIGURE 11.1.—Interrelation of Basic Elements of an Electronic Digital Computer.

the steps to be performed by the computer into a series of detailed instructions which control the operation of the computer.

3. *Storage* (*Memory*) *Unit*.—This unit stores information until needed by using electromechanical, magnetic, or electronic devices. Stored information is accessible and may be used only once or many times, as desired.
4. *Logical-Arithmetic Unit*.—This is the equipment that performs the four basic arithmetic operations. It can also compare numbers and thus distinguish between positive, negative, or zero values, all of which enable it to make logical decisions.
5. *Output Unit*.—This equipment issues the calculated results to the "world outside the computer" in the form of punched cards, magnetic tape, printed sheets, cathode-ray tube displays, automatic plotters, etc.

The general layout of a modern digital computer installation is shown in Figure 11.2.

11.2.3 Electronic Differential Analyzers

Electronic differential analyzers (EDA) can directly perform not only the four basic arithmetic operations available to the digital computer, but also the operation of integration, so that it is fundamentally suited for the automatic solution of differential equations. These operations are performed by converting the mathematical model of the system into an analogous physical system (into a mechanical system in the early days of differential analyzers[3,4] but into an electronic

See footnote References, end of Chapter.

FIGURE 11.2.—A modern digital computer installation.

system today [5,6]) so that differential analyzers are often referred to as analog computers.

Unlike digital computers, which perform all operations serially and which must solve differential equations by finite steps, differential analyzers perform many operations simultaneously and solve differential equations continually. Differential analyzers also have the ability to handle input functions which do not fit into any mathematical equation but which can be plotted on a normal two dimensional drawing.

The various functional elements of an electronic differential analyzer may be considered to be organized as follows:

1. *Input.*—The computer accepts information from the outside world via settings on potentiometers in the various amplifier circuits.
2. *Controls.*—The steps to be performed and measurements to be made are determined by the control panel (patchboard) wiring.
3. *Calculation.*—The calculation of results is accomplished by measuring and operating on various electrical quantities in the electronic analog circuits.
4. *Outputs.*—The results are displayed to the outside world by digital meters, oscilloscopes, inked strip charts, etc. Scaling factors almost always ensure that the response of the computer model will be in "slow motion" compared to the response of the actual system.

Figure 11.3 shows a photograph of a modern electronic differential analyzer installation with a simulator for transmission lines.

11.2.4 Miniature Replicas

A miniature replica consists of components that can be assembled to form a physically scaled-down model of the real system. The physical quantities measured on the model are directly related, through proportionality factors, to the physical quantities on the real system. Two types of miniature models have been extensively used over the years to solve transmission problems on electric power systems: the ac/dc network analyzer and the ac transient network analyzer. The ac and dc network analyzers were widely used throughout the industry until some 10 years ago[7] to study steady-state power

See footnote References, end of Chapter.

See footnote References, end of Chapter.

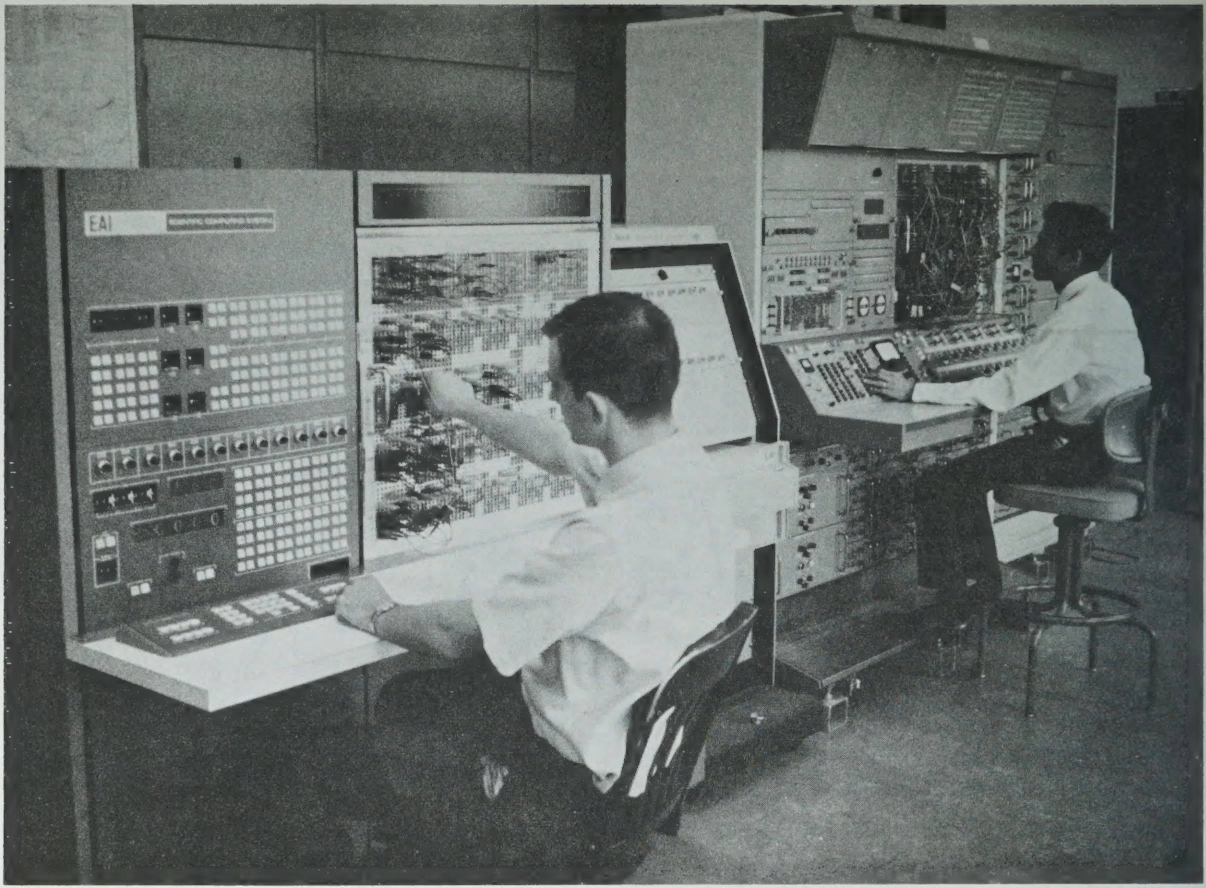

FIGURE 11.3.—A modern electronic differential analyzer installation.

flow and short-circuit currents and the electromechanical transietnts associated with system stability problems (Chapter 5). These analyzers have been displaced by digital computers, so that, today, relatively few are still in use, and then only for solving small-scale, limited problems. The transient network analyzer (TNA)[8], on the other hand, continues to play an important role in the study of electrical transients arising from lightning, switching operations (Chapter 4), and various other causes.

On the transient network analyzer, the parameters of the real-system elements are represented by inductance, capacitance, and resistance of proportionately scaled values. Since the analyzer is used, among other things, for the analysis of switching problems, accurate representation of distributed parameter components and nonlinear components is important.

Distributed parameter components are represented by repeated groups of lumped elements. Figure 11.4 shows an artificial three-phase section of a transmission line consisting of lumped elements with properly scaled values; a number of such sections are connected in series to represent a real transmission line. Nonlinear components are represented by lumped elements also. Figure 11.5 shows one approach to the miniaturization of a transformer, with lumped elements representing its leakage and magnetizing reactances.

An important component of the transient network analyzer is the synchronous switch, which permits switching operations to be repetitively performed in synchronism with the sweep circuit of the oscilloscope on which the analyzer output is observed. The switch permits switching to be performed at any desired instant during a cycle on each of the three phases of the miniaturized network. Figure 11.6 shows a photograph of a modern transient network analyzer installation.

Dc simulators are another important miniature replica used for the investigation of dc transmission systems. Their general design is similar to that of ac transient network analyzers, but, in addition, they include means for simulating the rectifica-

See footnote References, end of Chapter.

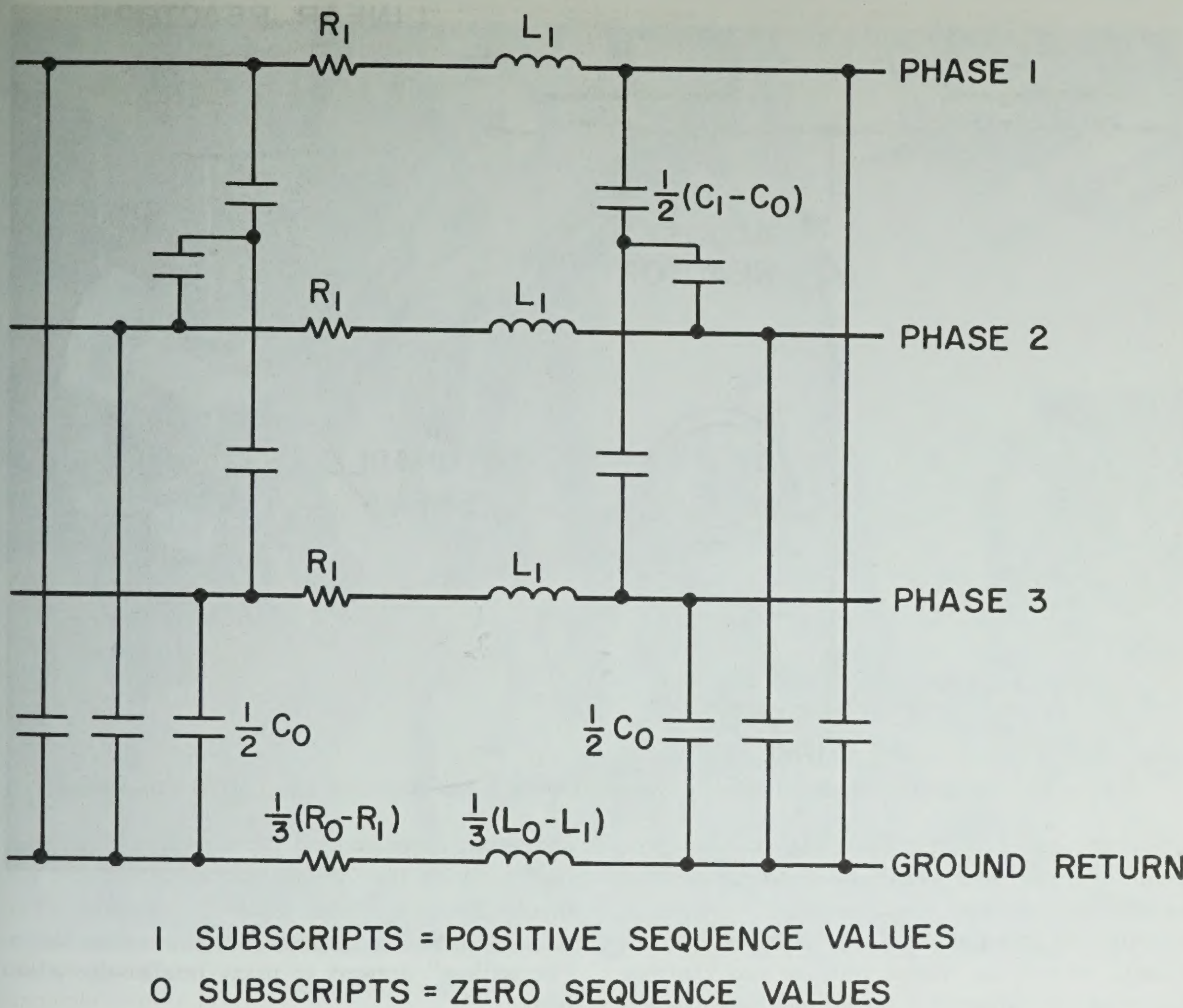

FIGURE 11.4.—Three-Phase Connection of Lumped Elements to Form an Artificial Line Section for Use in a TNA Installation

tion and inversion equipment. Depending on the simulator, the rectification and inversion equipment is either miniaturized or full-sized.

11.2.5 Hybrid Computers

A hybrid computer[9] is a combination of digital and analog machines. It allows simultaneous use of both digital and analog computation to best advantage. It has recently been used for dc transmission studies, isolated generator transient studies, and on-line system monitoring and control applications for improved system security and economy. Present use may be extended when more convenient integration of the two machines is devised.

See footnote References, end of Chapter.

11.3 Application of Analytical Tools

11.3.1 Digital Computers

Continued development of faster, higher capacity, digital computers has reduced the cost of computations which, in turn, has changed and widened the scope of power system engineering. Because the digital computer and its associated tabulating equipment have been in demand for business, accounting, and billing purposes, as well as engineering calculations, most electric utilities now own one or more such machines.

The vast majority of power system network studies are performed today on digital computers.[1] Power flow programs calculate voltages and power flows for a specific network with a specific load and generation distribution and level. They take into account the effect of the voltage regulating capability of generators and synchronous condensers, load-tap-changing transformers, and static

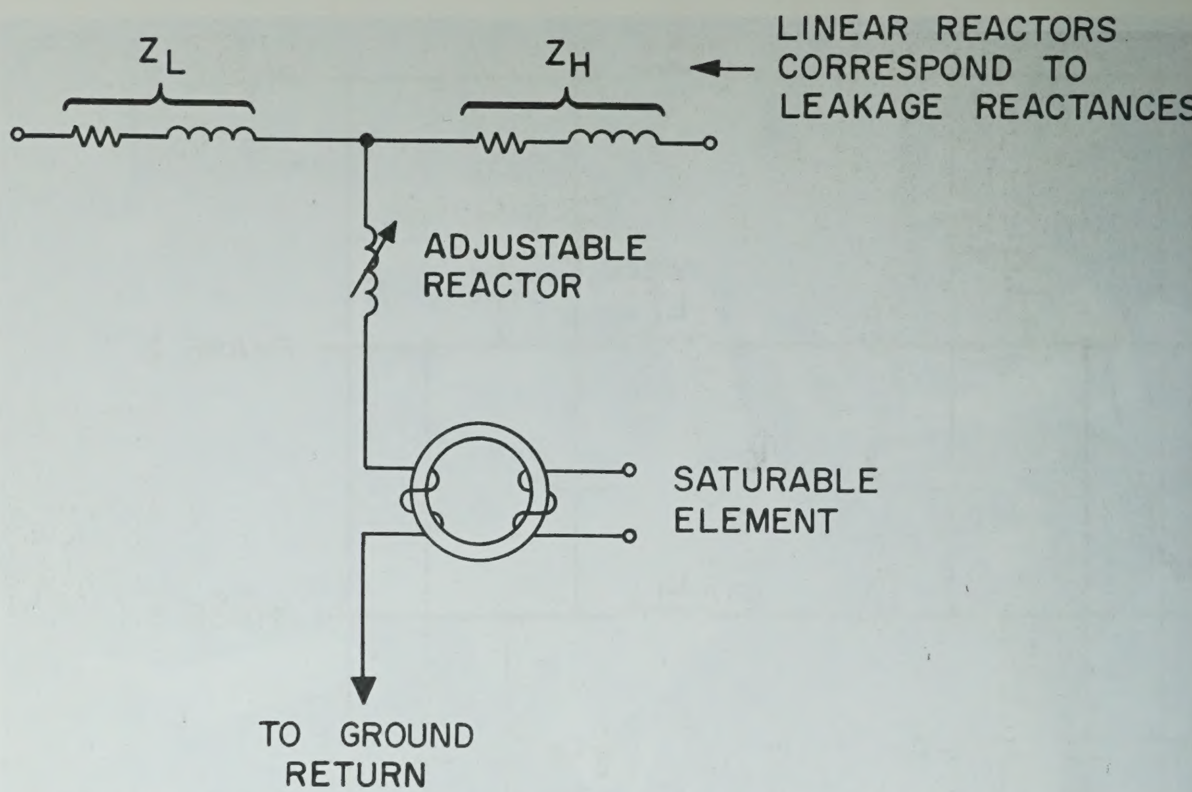

FIGURE 11.5.—Single-Phase Lumped Element Representation of a Transformer for Use in a TNA Installation.

capacitors and reactors. Transient stability programs calculate mechanical and electrical torques, speeds, rotor angles, and internal voltages of synchronous and induction machines on a power system, as well as system voltages and currents following a disturbance in the normal-state equilibrium, all with respect to time. These programs can usually also calculate information for evaluating the operation of relays during system disturbances. Short-circuit programs calculate fault currents, contributions to fault currents, and circuit breaker duties for a variety of faults and fault locations on a specific network. These programs are available with adequate capacity to handle the largest interconnected networks and can be extended, if necessary, as larger computer memories become available.

Other programs are available for studying electrical transients phenomena, for computing equivalent circuits, for simulating analog computer programs, for analyzing production costs, etc.

The computer time-sharing concept accommodates the need for the engineering solution of engineering problems having limited input and output requirements. Up to several hundred users may "share" a remote computer in which problems are submitted from a keyboard over telephone line to the computing center. Special, simplified languages for programming the computer have been developed by the various manufacturers and are readily learned in a few hours by personnel. With such equipment and training, engineers can obtain "immediate" answers to many smaller-size problems.

Process-control computers are increasingly being applied not only to the in-plant control of generating stations but also to the on-line control of certain power system operations. The goal is to improve the economy and reliability of power system operation.

11.3.2 Electronic Differential Analyzers

The EDA, a general purpose analog computer, can solve a number of localized dynamic problems associated with power systems. It is being used in such studies as (1) nonlinear oscillations (ferroresonance), (2) control of dc transmission, (3) switching surge studies, (4) variable speed motor systems, (5) discontinuities in loading, and (6) design of generator control circuitry. Generally, only some of the larger electric utilities possess machines of this type. Other utilities either rent time on an available machine or study the problem on a digital computer. Small EDA's are used by some for analysis and design of excitation systems and boiler and turbine control systems.

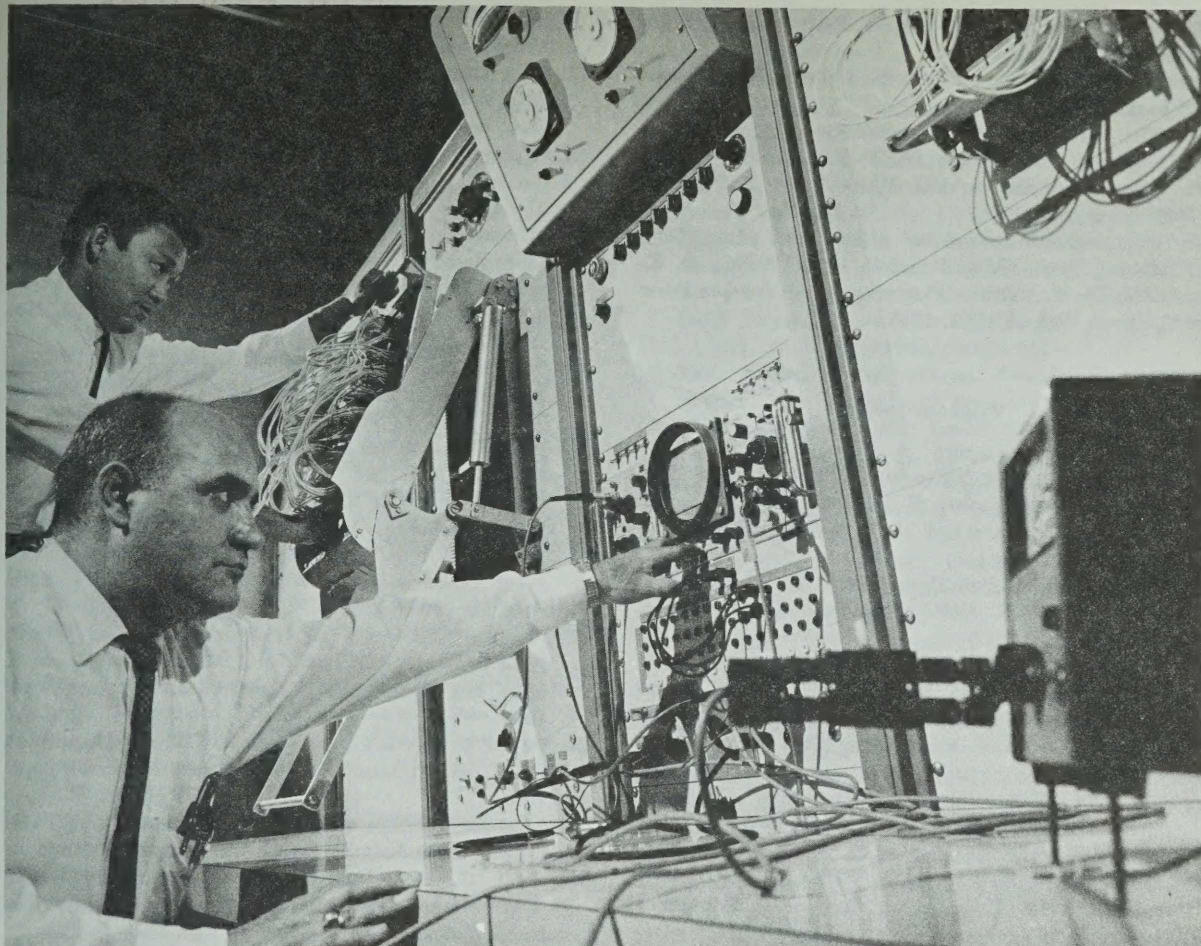

FIGURE 11.6.—A Modern Transient Network Analyzer Installation.

11.3.3 Miniature Models

Transient network analyzers are the most widely used miniature models today. Their application is particularly helpful in the study of power system problems, such as switching and lightning surges, including the effectiveness of lightning arrester action; circuit-breaker application studies, including the effect of controlled circuit-breaker pole closing, of impedances in series with the breaker elements during opening and closing operations, and of statistical distributions of pole span; and steady-state overvoltages on transmission lines, including the effect of saturation of non-linear elements. Like the differential analyzer, the transient network analyzer can also be used as an aid in the preparation of digital computer programs by serving as a "physical" model against which the validity of a digital program can be verified. There are relatively few transient network analyzers in the United States, and they are usually rented for periods of time by utilities requiring their use.

Dc simulators are being increasingly used in the study of dc transmission problems such as the steady-state transmission of power, electro-mechanical[10] and electrical[11] transients, and the effect of transients on mercury arc and thyristor conversion and inversion equipment.

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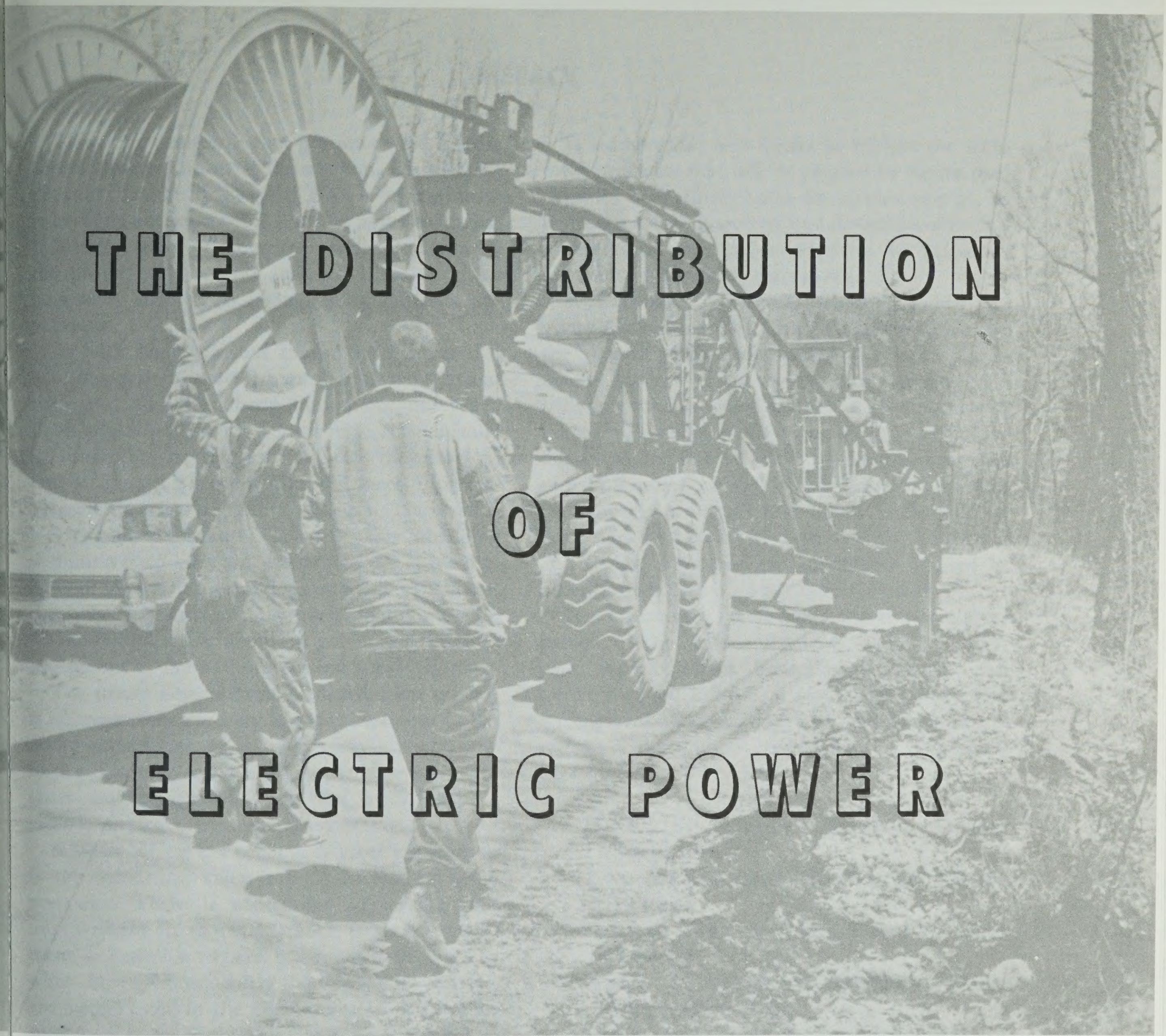
A REPORT TO THE FEDERAL POWER COMMISSION



THE DISTRIBUTION OF ELECTRIC POWER

PREPARED BY

THE DISTRIBUTION TECHNICAL ADVISORY COMMITTEE

FOR THE NATIONAL POWER SURVEY

JUNE 1969

PREFACE

This report concerns that portion of the electric supply system known as distribution. Distribution provides for the delivery of electric energy from generating or transmission facilities to the customer. It is the portion of the system most often seen by the public and, because it is so visible, it is the part most affected by changing standards of appearance.

As with highways and roads, the existing distribution system is the summation of many extensions and additions made throughout the years. Each addition is designed to provide economically for immediate loads, where and when they develop, and to fit into a pattern that will meet future requirements with minimum changes. The system is dynamic—constantly growing and changing without a fixed life span. It is a mixture of old and new, of overhead and underground, of urban and rural. It represents an investment in the order of 33 billion dollars or about 40 percent of the total investment in the nation's electric supply system.

The future development of distribution systems is of importance not only to the utilities but to the entire community. It can materially influence the future cost of electric energy, the appearance of cities and countryside, and the availability of electric service where and when needed.

A factor which has become of great importance is the increasing value society is placing upon aesthetics. There is widespread agreement that improvement in the appearance of our environment is desirable. There is less agreement as to what expenditures, solely for aesthetic reasons, are justified and in the best interest of the public. And there is not likely to be general agreement as to the value of specific measures, since aesthetics is a matter of individual personal judgment. It is to be expected that the appearance criteria for distribution systems will continue to change with the mood, needs and prosperity of the people. Therefore, it is essential in establishing aesthetic goals that the economics and other pertinent factors be understood and considered.

It is important and timely to explore the technical problems that will be created by future load densities and requirements for electric energy, to point out areas of concern and directions of probable developments, and to appraise the industry's capability to meet the future needs.

It is the view of the Distribution Technical Advisory Committee that a better understanding, by the general public and community and governmental leaders, of the factors that influence distribution systems would lead to better solutions to the mutual problems of tomorrow. The Committee has attempted to review the key aspects of present distribution systems and discuss factors that affect the future in a manner that can be understood by those not familiar with such systems. Technical and design data that are adequately covered in other publications have not been included.

The Committee membership constitutes a cross section of the various segments of the industry, with representatives from investor-owned and publicly-owned utilities, a regulatory agency and an engineering consulting firm. All geographical regions of the country are represented. The members are:

- Harold F. Pomeroy, Northeast Utilities (Chairman)
- T. A. Bettersworth, Pacific Gas and Electric Company
- Perry G. Brittain, Dallas Power & Light Company
- Walter J. Cavagnaro, California Public Utilities Commission
- Gerald Copp, Public Utility District No. 1 of Chelan County, Washington
- L. D. Cronin, Ebasco Services Incorporated
- S. Hord, South Kentucky R.E.C. Corporation
- J. A. Lasseter, Florida Power & Light Company
- Robert C. Stevenson, Jr., Chattanooga Electric Power Board

PREFACE

This report concerns that portion of the [illegible] industry's [illegible] distribution [illegible] ... [illegible]

[illegible]

It is important that [illegible] to explore the most [illegible] problems that will be [illegible] by future load [illegible] and requirements for electric energy, to [illegible] and areas of [illegible] and dimensions of [illegible] development, and to appraise the Industry's capability to meet prospective needs.

It is the view of the Distribution Technical Advisory Committee that a better understanding by the general public and governmental [illegible] of the factors that influence the [illegible] would lead to better solutions of [illegible] problems of [illegible]. The Committee [illegible]

[illegible]

Robert P. [illegible], Northeast Utilities [illegible]

T. A. [illegible], Pacific Gas and Electric Company

[illegible] G. [illegible], Texas Power & Light Company

[illegible] J. [illegible], Consolidated Edison [illegible]

[illegible], Public Utility District No. 1 of [illegible] County, Washington

[illegible]

J. A. [illegible], Florida Power & Light Company

Robert C. [illegible], Jr., [illegible] Power Board

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INTRODUCTION

The first successful electric distribution system was inaugurated in lower New York City on September 4, 1882 by Thomas Edison, using the electric light he had developed a few years previously. This was a low voltage direct current system which was installed underground in the neighboring streets.

The first commercial electric system using alternating current was successfully operated in 1886 at Great Barrington, Massachusetts. This predecessor of our present systems was installed by W. Stanley and G. Westinghouse using a newly developed English device called the transformer.

From this humble beginning, great new industries grew to provide the soft iron for magnets, copper wire, insulating materials, instruments and the thousands of items needed to build generation, distribution and utilization equipment for this newly-developed form of energy.

Electric utilities were formed to generate and deliver this energy to factories, homes and stores. With the electrification of manufacturing and creation of new industries, the production capability of the nation rapidly increased.

The quantity of electric energy consumed in the United States has continued to increase at a rapid rate throughout the years. The annual use has doubled about every ten years and this rate of growth is expected to continue through 1990. This growth is due partly to the increase in population and number of customers and partly to increased utilization per customer. A major factor in increased usage is the fact that the cost per unit of energy consumed has steadily decreased as shown in Figure 1. The lower cost per unit of energy supplied has been made possible by increasing load densities, technological progress and progressive leadership.

Historically, the only practical way that the demand for electric service could be met in most areas was by the installation of lines overhead. Overhead distribution continues to be the most economical way to supply electric energy except in extremely high load density areas.

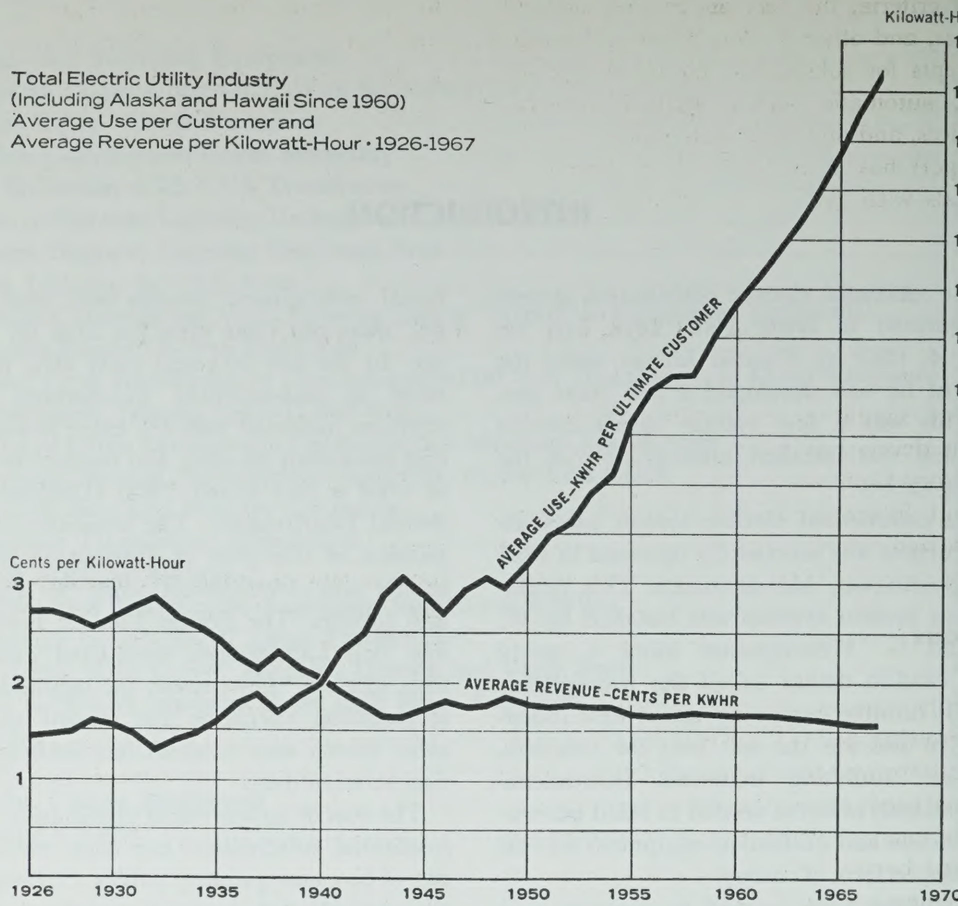
Through the years, various designs of conventional underground systems were tried in residential areas but costs were too high for widespread use. In the late 50's and early 60's, the development of pad-mounted transformers and polyethylene insulated primary cable made significant cost reductions possible, and marked the beginning of what is now called URD (Underground Residential Distribution). The possibility of rapid expansion of this type of distribution triggered research and development work by manufacturers and utilities. The Edison Electric Institute (EEI) and Bell Laboratories conducted extensive field tests whereby they proved the technical feasibility of installing telephone and electric cables in the same trench with random (no deliberate) separation between them.

The cost of underground distribution within new residential subdivisions has been reduced by the use of low cost primary cables, directly buried in the ground, pad-mounted transformers and new construction techniques. The previous cost of underground, which was from 5 to 10 times the cost of overhead, dropped to between 2 and 4 times the cost of overhead within a relatively short time and has continued to decrease.

Continuing through the 1960's, there has been increasing activity, at all levels of government, and by the electric utility industry and equipment manufacturers, to accelerate, promote and develop the capabilities to expand the use of underground distribution.

In 1964, the Institute of Electrical and Electronics Engineers (IEEE), sponsored a national conference on underground distribution. This conference not only brought together the ideas, thoughts and new developments to facilitate underground, but also stimulated application of underground in new subdivisions. The IEEE sponsored a second conference in 1966 and a third in 1969, both of which contributed to progress in the field.

The White House Conference on Natural Beauty, held in 1965, emphasized the importance of, and national concern with, the total environment. In 1966, the President appointed The Citizens' Advisory Committee on Recreation and Natural



Source: EEI Statistical Yearbook of the Electric Utility Industry for 1967

FIGURE 1.—Energy Use per Customer and Revenue per kwh.

ɩeauty to make recommendations for improving the environment. This Committee, in turn, created the Electric Utility Industry Task Force on Environment. The Task Force has studied various environmental problems confronting the electric utilities and has made recommendations to the Citizens' Advisory Committee. Some state commissions have issued directives and numerous local governments have instituted regulations concerning underground distribution.

The electric utility industry has accelerated its programs for underground installations in new areas and for conversion of overhead facilities in the congested areas where it will provide maximum benefits to the general public. Other positive actions being taken by the utility industry that relate to aesthetics of distribution include:

- Research and Development to lower the cost of underground.
- Improved designs of overhead lines.
- Aesthetic treatment of substations.
- Close cooperation with public agencies at all levels to obtain the proper balance between aesthetics and cost of service.
- Participation in programs that create interest in underground distribution.

The increasing role of underground in distribution is bringing about fundamental changes in system design and equipment criteria. The problem is far more complex than simply adapting overhead circuit designs and equipment to operate in an underground environment. The magnitude of this problem, together with the popular appeal of underground, has focused much attention on the subject as will be noted in the following sections.

The future holds many new challenges arising from the rapid increase in population densities, the growing use of electric energy, the increasing requirements for reliability, the changing en-

vironment criteria, the decrease in sites available for facilities, and other factors. These will require new concepts for substations, circuit design and capacities, automatic control systems, construction practices, and operating techniques.

This report has been divided into three parts. Part I deals with general considerations relating to the distribution system. Part II deals with distribution technology. Part III is devoted to present and projected costs of distribution, with particular consideration of the effect of the increasing role of underground. Additional details regarding certain aspects of distribution are contained in three appendices.

CONCLUSIONS AND RECOMMENDATIONS

The more significant conclusions and recommendations developed by the Distribution Technical Advisory Committee during its study of the present and future electric distribution systems are summarized below:

Conclusions

Historically, the electric utility industry has met the growing load requirements of its customers and improved its quality of service to meet the customer needs at a continually decreasing cost per kWh of energy sold. There appears to be no technological barrier to meeting the electric service requirements of the future.

The compatibility of distribution systems with the environments in which they are located has become an increasingly important consideration. The location and appearance of both substations and overhead lines have become primary criteria for the planning and design of distribution systems. A strong trend to use underground rather than overhead construction for distribution lines has developed.

Most of the existing distribution lines in the country are overhead and the extent of these lines has been increasing annually. This increase will continue through 1990, but at a declining rate because of the trend to underground construction for new lines.

Techniques have been developed for improving the appearance of overhead lines by the selection of materials, structural shapes and colors which are in harmony with the environment. The improved overhead lines should meet appearance objectives in many situations.

The use of underground construction for new distribution lines is increasing rapidly. It is estimated that in 1968 about 20 percent of new lines built in the country were underground. This percentage is expected to increase to about 70 percent by 1975 and to about 90 percent by 1990.

Underground distribution lines cost more than overhead. During the last decade, the cost difference has been much reduced by the development of new materials and installation techniques, particularly for lines to serve new residential subdivisions. It is expected that this cost differential will be further reduced, but will not be eliminated in the foreseeable future.

Conversions of existing overhead distribution lines to underground is much more costly than is the underground construction of new lines. The investment required for a general conversion program to eliminate most of the existing overhead distribution lines by 1990 is estimated to be from 170 to 200 billion dollars.

The adverse visual impact of the existing overhead lines can be reduced to a significant extent by selective conversion programs of limited magnitude. The optimum environmental improvement per dollar expended for conversions can be obtained by selecting overhead lines that have a particularly adverse impact because of congestion of facilities, location, or exposure to public view.

Because of the trend to underground distribution and other factors, it is not expected that the past rate of decrease in the average cost per kWh attributable to distribution will continue in the future. The Committee studies indicate that this cost can be kept at about its present level or declining at a very much reduced rate through 1990, if

(a) The cost of capital and tax rates do not rise significantly above present levels.
(b) The average annual rate of increase in the cost of distribution material and labor does not exceed that of the past 15 years.
(c) There is no substantial increase in the rate of expenditures to convert existing overhead lines to underground.

Some increase in the rate of expenditures for conversions is expected, and the potential effect on costs has been studied. However, there is no indication of what the magnitude will be nor of the sources of the funds that will be required, and therefore it is not feasible to predict the impact of increased conversion expenditures upon the future cost of power.

Recommendations

Efforts to make distribution facilities more compatible with their environments by choice of location, consideration for appearance in the design of visible facilities, and the use of underground construction for new lines where economically feasible should be promoted and encouraged by all concerned.

All communities should include provisions for substations, associated high voltage supply lines, and distribution lines, as a necessary and vital part of their future plans. The increasing use and the dependence placed on electricity will require more substations to be located within the communities served.

Research and development work on distribution system needs should be continued and accelerated. The more important research needs are:

(a) To provide equipment for the underground systems of the future that will further reduce the cost of underground distribution and improve service reliability.

(b) To improve reliability, appearance and economy of overhead distribution systems.

(c) To provide equipment to realize the economies possible with higher primary and secondary voltages than those now in use.

The research and development activities of the utilities and the equipment manufacturers should be coordinated to develop a consensus as to requirements and thus minimize misdirected efforts.

There should be some increase in the rate of expenditures for converting overhead to underground. In determining the extent of conversion programs and the sources of funds for them, the potentially adverse impact upon the future cost of electric energy should be given careful consideration. The conversion programs should be selective in character in order to achieve optimum environmental improvement for the amount of money expended.

Regulatory bodies and government authorities at all levels, in making decisions affecting electric distribution, should give full consideration to all of the criteria that distribution systems must meet. A judicious balancing of need to meet load requirements, quality of service, environmental compatibility, and cost is essential. Restrictions on location, design or installation of facilities that would unnecessarily increase costs, delay service to customers, or impair service reliability should be avoided.

Uniformity of government regulations is desirable to the extent that it is compatible with differing local conditions. Model codes, standards and rules should be developed by national associations and used as guidelines for state and local rules governing utility installations.

PART I—GENERAL CONSIDERATIONS

SECTION 1—THE ELECTRIC UTILITY INDUSTRY

The electric utility industry is a composite of many individual utilities operating under widely different types of organizations with different financial structures, controls and regulatory requirements.

Investor-owned utilities comprise the largest segment of the industry. They distribute about 77 percent of the total electric power requirements of the United States. Their business structures are similar to those of other investor-owned enterprises insofar as financing methods and tax obligations are concerned. These utilities are subject to governmental regulation and control in varying degrees under local, state, and federal authorities.

Publicly-owned utilities include those owned by the federal, state and municipal governments, public power districts and rural electrification cooperatives. This sector distributes nearly all of the remaining 23 percent of the electric power requirements of the nation. Financing methods and tax obligations of publicly-owned utilities vary with the type of utility but in general involve lower costs than the corresponding costs borne by the investor-owned utilities.

The electric power produced and used internally by individual industrial plants is not considered part of the electric utility industry and is outside the scope of this report.

TABLE I-a

Major System Components

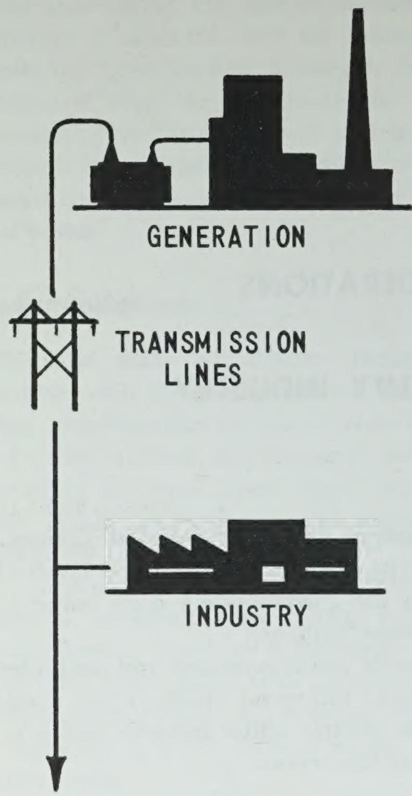
Component	Approximate percentage of total investment
Generation	40
Transmission	17
Distribution	40
Office buildings, service centers, etc.	3
Total	100

Major Functional Components

The major functional components of an electric utility system are shown in Table I-a.

Generation is that system component in which other forms of energy (hydraulic, fossil fuel, nuclear and geothermal) are converted to electrical energy. The generating plants may be isolated and separated by many miles from the load centers or they may be centrally located units directly integrated with the distribution system.

Transmission is that system component involved with conveying large blocks of electrical energy from the sources of generation to bulk substations for ultimate distribution to the customer. A few industrial customers, with large power requirements, are supplied directly from the transmission system. The transmission system is in effect a high voltage network consisting primarily of overhead lines operating in excess of 50,000 volts. These transmission lines link virtually all sections of the country together electrically, to permit the economic interchange of power. This massive transmission system requires large high voltage substations situated at strategic locations to provide the switching and control which are essential to assure maximum reliability.

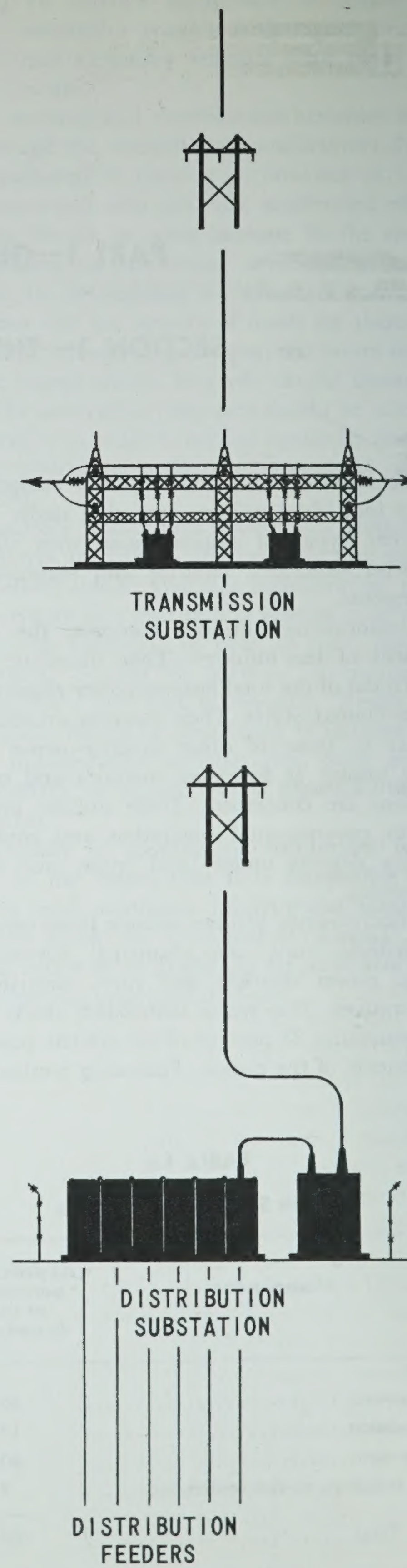


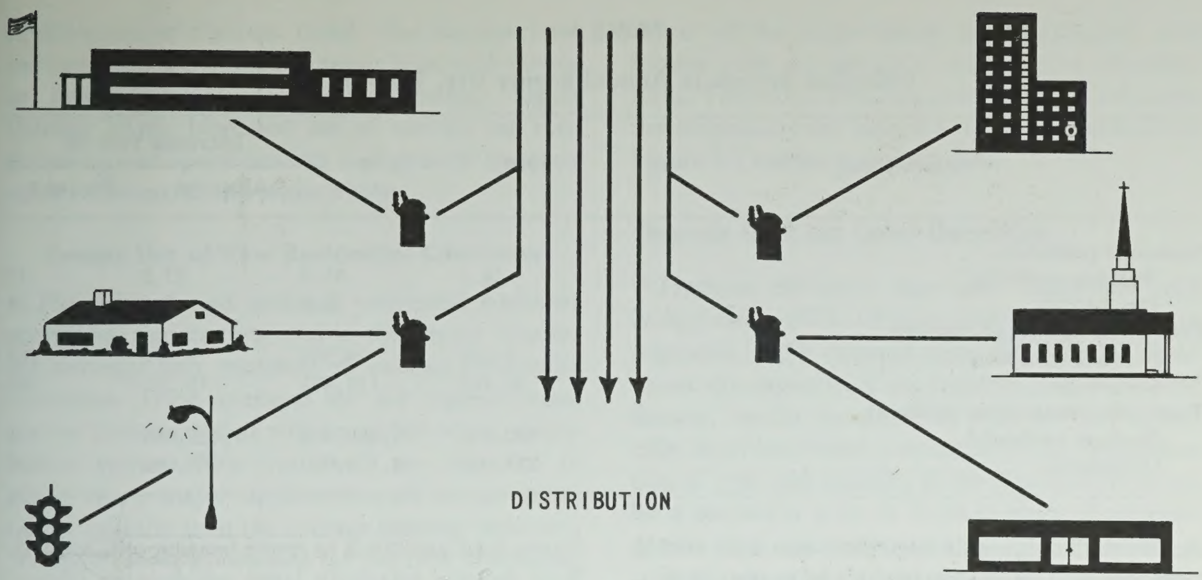
Distribution is that system component that delivers the energy from the generators or the transmission system to the customers. It includes the substations that reduce the high voltage of the transmission system to a level suitable for distribution, and the circuits that radiate from the substation to the customers.

The distribution circuits that carry power from the substations to the local load areas are known as primary circuits or feeders and generally operate at voltages between 2,400 and 34,500 volts. These circuits may be overhead or underground depending on the load density and the physical conditions of the particular area to be served. The vast majority are constructed overhead on wood poles that may also support communication facilities and street lights. Street lighting is an important part of the distribution system.

Distribution transformers are installed in the vicinity of each customer to reduce the voltage of the primary circuit to 120/240 volts or other utilization voltage required by the customer. Secondary circuits carry the power at utilization voltage from the distribution transformers to the customers.

The components of the distribution system are reviewed in more detail in Part II.





SECTION 2—DISTRIBUTION SYSTEM LOADS

This section considers present loads served by electric distribution systems and anticipated growth of these loads to 1990.

Present Energy Use

The Federal Power Commission National Power Survey Regional Advisory Committees have forecast customer growth and energy use through 1990. Their forecasts for the year 1970 have been used in this report to indicate the magnitudes of present loads.

In 1970, the electric utility industry in the contiguous USA is expected to sell about 1,389 billion kWh of energy to about 69.7 million ultimate customers. These estimated 1970 sales of energy are shown by customer classes in Table I-b.

The industrial and miscellaneous customers use about half of all of the energy sold, but numerically, are less than 1 percent of the total customers. The power requirements for some large industrial customers are delivered at transmission voltage or through single-customer substations connected directly to the transmission system. The distribution system's principal function is to deliver the energy to the remaining industrial and miscellaneous customers and to the other three categories of customers who use the remaining 50 percent of the energy. Of these, the number of farm customers is decreasing, although the energy use per farm is continuing to increase. Most of the load growth on distribution systems is expected in the other two categories of nonfarm residential and commercial customers.

Table I-b shows the national average annual kWh use per customer for each category. Regional averages deviate significantly from the national averages. For example, nonfarm residential customer averages range from 4,815 kWh in the Northeast to 9,415 kWh in the Southeast Region, and commercial customer averages range from 32,689 kWh in the Northeast to 42,408 kWh in

TABLE I-b

Energy Sales by Customer Classes, 1970

Class of customer	Thousands of customers	Millions of kWh	kWh per customer
Nonfarm residential	58,134	379,547	6,529
Farm[1]	3,429	36,710	10,705
Commercial	7,629	278,229	36,468
Industrial and miscellaneous[2]	552	694,908	1,258,000
Total	69,744	1,389,394	19,900

[1] Excludes irrigation and drainage pumping.

[2] Includes irrigation and drainage pumping, street and highway lighting, electrified transportation, and other categories.

TABLE I–c

Estimated Growth in Annual Energy Use, 1970–1990

Description	1970	1990	Increase 1970–90	
			Amount	Percent
Customers (millions)				
Nonfarm residential	58.1	85.3	27.2	47
Commercial	7.6	10.2	2.6	34
kWh Consumption per customer				
Nonfarm residential	6,529	16,505	9,976	153
Commercial	36,468	111,675	75,207	206
Total kWh consumption (millions)				
Nonfarm residential	380,000	1,409,000	1,029,000	271
Commercial	278,000	1,138,000	860,000	309

the West. Considerable variations also exist within each region. Use per customer and customer density are significant factors in the cost of distributing power.

For residential customers, variations in average use are influenced by such factors as the relative cost of electricity and competing forms of energy, climate, size and type of homes, average family size and income level, age of homes and adequacy of wiring, and living habits in the region or area.

Forecasts of Growth in Energy Use

The Regional Advisory Committee forecasts of growth in energy use by nonfarm residential and commercial customers for the period 1970–90 for the contiguous USA are summarized in Table I-c.

In order to supply the predicted load growth over this 20-year period, the capacity of the distribution systems in 1990 must be almost four times that of 1970.

Factors Causing Growth in Residential Energy Use

An increase of 153 percent in average use per nonfarm residential customer is predicted. This is a continuation of a long sustained historical trend. This trend has resulted from the introduction through the years of many new devices for utilizing electricity in the home combined with increasing acceptance and use of such devices after they become available. Increased use has been encouraged by the rising trend of per capita personal income and the declining trend in the unit cost of electricity.

Of the presently available devices for utilizing electricity in the home, the largest potential for future load growth is in space heating and cooling. Both require relatively large amounts of energy. In 1968, only about 5 percent of the homes in the country were electrically heated and 37 percent had some form of electric air conditioning. The use of air conditioning is increasing rapidly and it is expected that by 1990, most of the homes in the warmer areas and most of the new medium to high priced homes elsewhere will be air conditioned. Electric space heating is being installed in more new homes, apartments and commercial buildings each year. Forecasts show that electric space heating will continue to take a larger share of the new construction market. The conversion of other types of heating systems to electricity is a tremendous potential market for electricity.

Present saturation of most other important electrical appliances in homes ranges from 18 percent for dishwashers and food waste disposers to 47 percent for electric ranges. Saturation of refrigerators, clothes washers and television sets is already above the 90 percent level.

It is expected that new uses for electricity in the home will continue to be developed, although it is difficult to predict them specifically. Electric incineration and electric garbage processing are being developed. The storage battery powered automobile is currently receiving much study. If electric automobiles prove to be practicable for general use, a tremendous increase in electric energy use will result. Battery charging from home outlets and by commercial establishments have both been suggested.

Factors Causing Growth in Commercial Energy Use

An increase of 206 percent in average use per commercial customer is predicted. This is also a

continuation of the past trend. The increased use per customer is expected to result from such factors as larger average size establishments, higher lighting levels, increased use of electric air conditioning and space heating and growth in many other commercial uses of electricity.

Energy Use of New Residential Customers

The regional and national residential customer energy use figures presented in this report thus far are averages that represent all existing residential customers. These averages are not representative of new customers that will be added to the distribution system. New customers are expected to install more major appliances and to use more energy initially than the average existing customer.

Supplementary forecasts for the new residential customer have been prepared from data collected by the Distribution Technical Advisory Committee. The data represent responses the committee received from questionnaires sent to investor-owned and publicly-owned utilities throughout the United States. National average energy-use characteristics for residential customers in newly developed or redeveloped areas are tabulated in Table A-d of Appendix A. To describe the energy use of this class of customer more accurately, two sub-classifications have been established, single-family multifamily residential. The energy use requirements of the single-family and multifamily customers vary considerably within these classifications. Therefore, small-use, medium-use and large-use projections are included for each classification. Figure I-1 summarizes these data.

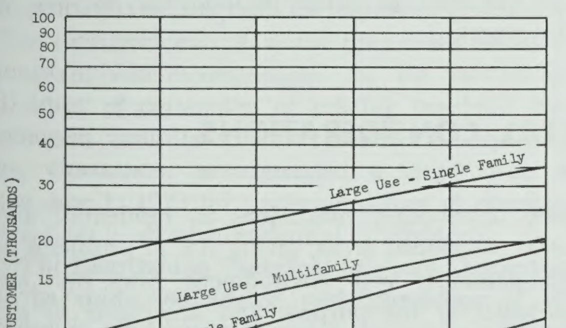


FIGURE I-I.—Energy sales per new residential customer. Single-family and multifamily customers.

Growth in Area Load Densities

Previous discussion has been concerned with energy use in kWh. Of more interest to distribution engineers is kW demand since the demand determines the capacity of the facilities required. Load density, usually measured in peak kW per square mile, is an important parameter in the determination of type and capacity of the distribution system for a particular area. It is the product of customer density and coincident peak load per customer.

Both customer density and load per customer are increasing. The individual customer is using more electricity as he adds appliances and equipment in his home or business establishment. The residential customer is showing an increased preference for apartment living, which results in increased customer density. These two factors, greater use per customer and higher customer density, will result in higher load densities in urban and suburban areas. These increasing load densities will influence the design, economics, and performance of the future distribution systems that supply these areas.

Residential customer densities vary over a wide range. Developments of single-family homes are generally in the density range of one to eight homes per acre. With low rise multifamily buildings, there may be 20 or more family dwelling units per acre, and with high rise apartment buildings, 100 or more.

Customer density, per customer energy use and peak load are interrelated. Although area load increases as customer density increases, the energy use and the peak load per customer tend to decrease for several reasons. Single family homes on small lots are generally smaller and occupied by lower income families than those on larger lots. Multifamily dwelling units are generally occupied by smaller families than single-family units and the occupants tend to spend less time at home. Energy requirements for comparable air conditioning and space heating are generally less for multifamily units than for single-family units of equivalent size because there is less exterior wall and roof area.

In the business centers of cities, load densities can be much higher than in predominantly resi-

dential areas. These densities vary with the size of the business center, the heights of the buildings, and other factors. In major metropolitan centers, densities of 100,000 to 300,000 kW per square mile are typical now and densities of 350,000 to 1,000,000 kW per square mile are projected for 1990.

Due to the many inter-relationships involved, no attempt is made in this report to quantify residential area load densities. Instead, projections of growth in demand per new residential customer are provided. Forecasts of percentage growth of noncoincident demands for single-family and multifamily residential customers are presented in Table A-f of Appendix A. If it is assumed that diversity remains unchanged for each customer classification throughout the period of consideration, then the projections are representative of coincident demands as well.

The projections indicate that the noncoincident demand per new residential customer in 1990, both single-family and multifamily, small and medium use, will be approximately two times that of 1970. The large-use customer demands in 1990, single-family and multifamily, will be approximately one and one-half times that of 1970.

It is estimated from other data collected by the questionnaire that the national average coincident demand for existing nonfarm residential customers in 1990 will be approximately two and one-half times that of 1970. This projected ratio of future to present demands is greater than the ratios projected for new customers. This is because new homes generally use more electricity than older ones initially, but this differential will tend to decrease because demands of older homes have a higher growth rate and new homes will approach a saturation level sooner.

Future area load densities can be estimated by utilizing known information obtained from recent installations, such as class of customer, average kW demand per customer, customer density and diversity, and then applying the appropriate growth rates tabulated in Table A-f for the year under consideration. Adjustments can be made for differences between the existing and the expected future installations with respect to customer density and diversity.

The electric utility industry's 20-year forecast of greater energy sales, higher customer demands and higher load densities is one of continuing growth. The 1990 forecast of distribution system loads, four times greater than 1970, serving a population half again as large, portrays the magnitude of the task ahead for the industry. A very large increase in distribution system investment will be required. New distribution design concepts will need to be developed and new equipment will be required that is as yet undeveloped. In these areas of concern are many factors that must be fully appraised before the impact of the industry forecast can be evaluated. These factors are discussed in detail in following sections of this report.

SECTION 3—ENVIRONMENTAL CONSIDERATIONS

There is no subject of more interest to the utility industry than the appearance of distribution facilities and their compatibility with the environment. There is also no subject that is causing more uncertainties about future distribution costs and construction practices.

General

Within the past few years, increasing concern has been expressed by various groups at the federal, state and local levels about the appearance of the nation's cities and countryside. Overhead electric distribution lines have been one of the items of concern in this respect. Growing load and population densities have increased the need to locate new distribution substations in residential and other developed areas, giving rise to problems of compatability with environment. Sites that are suitable for the purpose and acceptable to the public are decreasing at an alarming rate.

The White House Conference on Natural Beauty, in 1965, focused national interest on the environment and the appearance of the nation's cities and countryside. An important development from this Conference was the establishment of The Citizens' Advisory Committee on Recreation and Natural Beauty, by the President of the United States in May, 1966. This Committee, under Chairman Laurence S. Rockefeller, has pursued the problem and recommended changes that are far-reaching and would affect the entire population in one way or another.

Assisting the Citizens' Advisory Committee was the Electric Utility Industry Task Force on Environment. This Task Force consisted of members of the Citizens' Advisory Committee, the chief officers of several investor-owned utilities, management representatives of publicly-owned utilities, members of state regulatory commissions and telephone company representatives. This Task Force set a target date of 1975 for the undergrounding of electric distribution lines in all new residential areas. Regarding existing overhead distribution lines, the Task Force Report states, "Conversion of all existing distribution lines from overhead to underground, because of the magnitude of the job, would prove virtually impossible. It is unrealistic to expect that it can be accomplished in its entirety. Certain of the lines, however, should be undergrounded as soon as possible. The effort must be directed at areas of primary consideration, which are generally within urban and suburban areas."

On December 27, 1968 the Working Committee on Utilities submitted a report to the Vice President and to The President's Council on Recreation and Natural Beauty. Commissioner Carl E. Bagge of the Federal Power Commission was Chairman of this committee of Federal Agency representatives. Recommendations were made for protection of natural, historic, scenic and recreation values in connection with transmission facilities and for coordination of programs for improved generation. The establishment of a comprehensive national program was recommended for the formidable problem of conversion of existing overhead distribution facilities to underground. In addition, the Committee recommended a target date of January 1, 1973 for undergrounding of distribution lines in all new residential subdivisions.

The Distribution Technical Advisory Committee in its study, considered undergrounding of all types of new extensions as a composite without reference to a specific target date for installation of underground in new residential subdivisions.

In order to provide an adequate supply of low cost electric energy to meet the nation's future needs, economical solutions to the environmental problems are necessary. The essential elements of a program to achieve such solutions include:

Increased use of underground distribution and reduction of underground construction costs to the extent practicable.

Improvements in appearance of overhead lines.

Improvements in appearance of substations.

Location and design of all facilities to meet reasonable environmental requirements.

Judicious allocation of expenditures for aesthetic purposes.

Improved coordination of distribution planning with community planning.

Due consideration by regulatory, legislative and other governmental bodies of all factors involved in the location and design of distribution facilities.

An informed public.

Many aspects of distribution design and construction practices are presently undergoing rapid changes to meet changing criteria relating to aesthetics. Overhead lines, underground lines, and substations are reviewed separately in the remainder of this section.

Overhead Lines

In the minds of many, the term overhead electric line creates a vision of an unsightly pole line with multiple cross-arms, numerous wires and conspicuous appurtenances such as large transformers, etc. There are many lines of this description in existence. The criteria for the design of these lines were primarily performance and minimum cost and appearance was not a major consideration. Their presence was a sign of progress and the fulfillment of the nation's need. These lines did satisfactorily fulfill the primary purpose of their existence, which was to provide an adequate supply of low cost electric energy essential to the nation's growth and economic development. Today, this country produces about 1/3 of the world's total electric energy and enjoys a high standard of living. The abundance of low cost electric energy has been a major factor in these achievements.

The high standard of living enjoyed by the people of this country has led to an increasing interest in the quality of our environment, and thus has made appearance an important criterion in the design of overhead lines. In response, utilities and manufacturers have developed many new designs, materials and concepts that have materially improved the appearance of overhead facilities. Many of the newer lines are in sharp contrast to their predecessors from the standpoint of appearance.

A basic approach has been to eliminate or reduce the clutter. This has been done by minimizing the number of conductors carried on one pole

line, elimination of crossarms, use of appurtenances with improved appearance and other design changes.

The color of components has also received attention. Insulators, transformers and other equipment used for most new construction have a soft almost neutral color that blends well with sky and most surroundings. In some areas, wood poles are being purchased with a preservative that permits staining the poles to a color compatible with their surroundings.

Major improvements in appearance of overhead lines are being achieved by avoiding the installation of large transformers and their associated large service conductors on pole tops or overhead platforms. This is accomplished by using suitably enclosed transformers on or below the ground, usually located on the customer's property. The transformer, so located, is connected to the overhead primary line by a cable installed underground from the base of the pole to the transformer, eliminating the need of large low voltage overhead conductors from poles to buildings.

Route selection is also important to the appearance of distribution facilities. By taking advantage of natural screening, the silhouette is softened and the line better harmonizes with the surroundings. In some locations, construction of lines along rear property lines is a practical way of obtaining screening.

Considerable improvement in appearance is being obtained in some high density residential areas by burying the service conductors that run from the street to the houses. This is particularly effective where houses are closely spaced and service conductors extend across the street.

In some areas, concrete or steel poles are being used in lieu of wood to improve appearance. These poles are produced in various shapes with clean lines and have a uniform appearance. Fiberglass components have become available for use in lieu of some of the hardware and supports formerly used. These are made in attractive shapes and should lead to further improvements in appearance of overhead lines.

By use of modern materials and designs, overhead lines that meet the appearance requirements in many locations are being built at a cost significantly less than underground.

Underground Lines

Underground construction is the solution usually proposed in response to objections to the appearance of overhead lines. While underground is desirable from an appearance standpoint, it has the disadvantage of higher cost. Historically, underground systems have been confined principally to high load density areas such as the downtown sections of the larger cities. Such systems require designs and equipment with an extremely high degree of reliability and capability for growth without major changes. Duct systems and manholes are a necessity. The costs of such systems are high and cannot be justified for use in low load density areas.

In recent years, a lower cost underground system has been developed for use in residential and other low density areas. Development is expected to continue at a rapid rate. Costs have been considerably reduced, but still remain significantly higher than for overhead construction.

The use of underground instead of overhead is finding increasing application in new residential subdivisions, apartment developments, and shopping centers. Many of these areas are served by underground cables and above ground pad-mounted transformers and equipment. Considerable research and development has been devoted to the above ground equipment. The low profile pad-mount transformer is being used in new residential areas, and located in either the front or back of the lots. It can be readily screened to conform to the landscape. The large pad-mount units required for apartments and commercial installations can be located, painted, and architecturally treated so that they appear to be a planned part of the development rather than the identifiable electrical supply.

Enclosures similar in appearance to the pad-mount transformers are used to house protective devices and equipment that are essential to the electric distribution system.

For high use homes located on large lots, an individual type of pad-mount tranformer with integral metering enclosure is being used in some areas. This equipment can be installed adjacent to the building, where it can be obscured by appropriate plantings.

Efforts are also being devoted to elimination of above ground equipment. Submersible transformers in the 15 kV class for installations in residential developments have received considerable attention and are now being used in many areas, particularly with front lot installations. Where these transformers are installed in underground enclosures, the only visual evidence of this installation is a grating, which is required

to permit access to the transformer and to dissipate the heat generated. The cost of this type of installation is higher than for the pad-mount system and the technical problems associated with it are more severe and difficult to resolve.

System components that can be directly buried and which will have a long service life are also under development. Success in this effort would improve appearance by eliminating the gratings.

The reliability of the low cost type of underground system is not expected to be materially different than that of overhead and the operation and maintenance costs may be higher. Thus, the use of underground construction is appropriate only in areas where the improvement in appearance justifies the substantially higher cost. In some situations, a combination underground-overhead system will be more appropriate when both cost and aesthetic gains are considered.

Conversion of Existing Overhead to Underground

Conversion of existing overhead distribution to underground is much more costly than is the use of underground instead of overhead construction for new lines. Conditions in built-up areas are much less favorable for efficient underground construction. Further, the investment in overhead lines, having already been made, cannot be avoided or recovered by conversion to underground. Elimination of existing overhead lines usually involves substantial costs for work other than undergrounding the distribution lines. This work includes the undergrounding of telephone and municipal signal circuits, providing poles and circuits for street lights, and rewiring the customer's service facilities.

For these reasons, widespread conversion of existing overhead distribution is not economically practicable. Nor is general conversion of the existing lines necessary to significantly reduce the adverse visual impact of existing overhead distribution. Lines vary greatly in their visual impact, depending upon design, condition, location and exposure to view. Selective programs for conversion of the overhead lines that are most conspicuous and objectionable in appearance can produce optimum results in appearance improvement per dollar expended for conversions. Conversion of overhead lines in locations where they are not incompatible with the surroundings would increase cost of electric service without corresponding aesthetic benefits.

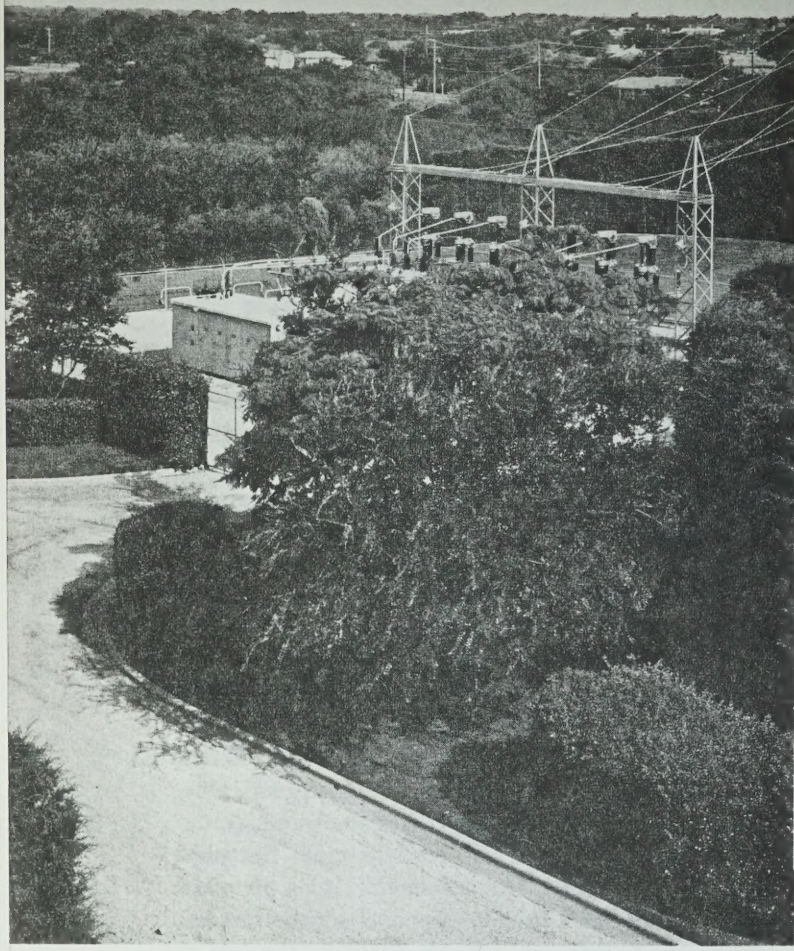
Since appearance is a subjective matter, determining the specific locations where the gain in appearance justifies the cost of conversion is often a matter of reconciling widely differing opinions. The timing of such conversions is further complicated by the fact that significant savings can be realized if conversion is done at the time when the overhead facility requires rebuilding to increase capacity or to conform to changing land use. This requires close cooperation and coordination of planning between the utilities and local governmental agencies. There are uncertainties of future electric loads and of community development in specific areas, including widening or major changes in streets. These uncertainties inhibit long range planning of specific conversions and make long range time schedules for conversions generally impracticable. Ordinances or regulations that force premature conversions, in the long run, produce less benefit per dollar expended than those that permit orderly and timely conversions.

Although general conversion of the existing overhead lines is not economically practicable, some increase in the rate of conversion is desirable and expected in order to meet the need for environmental improvement. It is essential that this increase in rate of conversion be limited, so as not to have an adverse effect on the cost of power. It should be on a selective basis in order to achieve the maximum aesthetic benefits per dollar of cost.

Substations

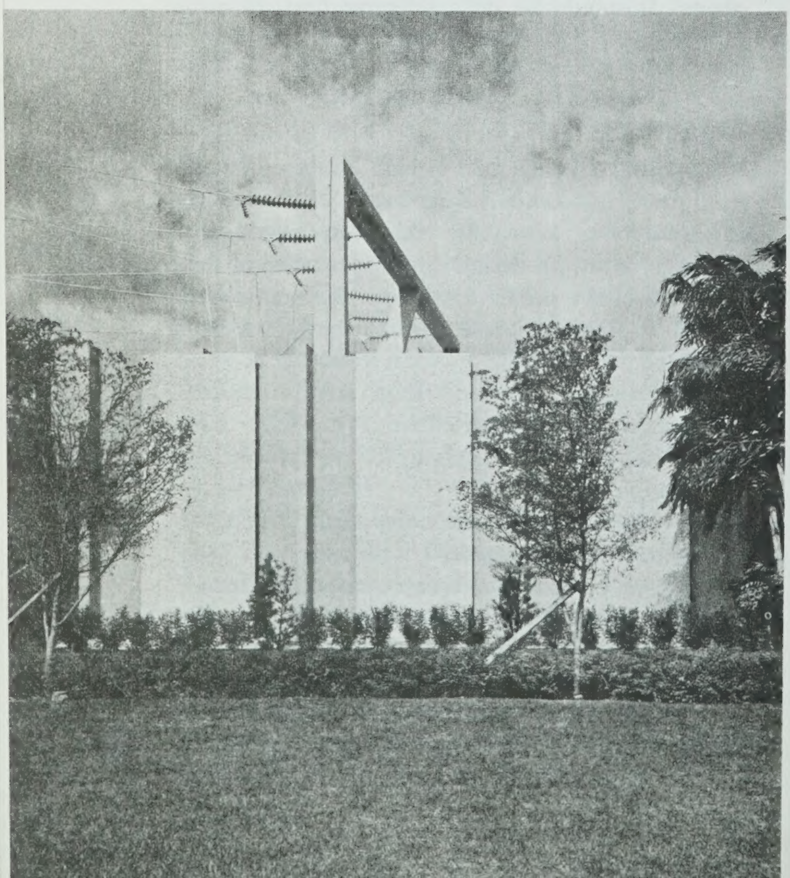
To fulfill the electric energy requirements of the future, additional substations will be required in developing areas. Considerable attention is being given to the design and appearance of these installations in order that they conform to environmental requirements. The techniques being used include:

- Simplified designs that minimize components and silhouette.
- Reduction in height of structures and equipment.
- Use of equipment colors that harmonize with the environment.
- Use of colors to create aesthetic effects.
- Artful landscaping.
- Interesting architectural treatment with panels, walls or enclosures.
- Use of short underground runs for primary feeders to reduce overhead congestion in the immediate vicinity.



ACCENT ON APPEARANCE IN DISTRIBUTION

The changes taking place in distribution are illustrated in the following photographs which show new designs of overhead lines, aesthetic treatment of substations and the trend to underground construction in new subdivisions.

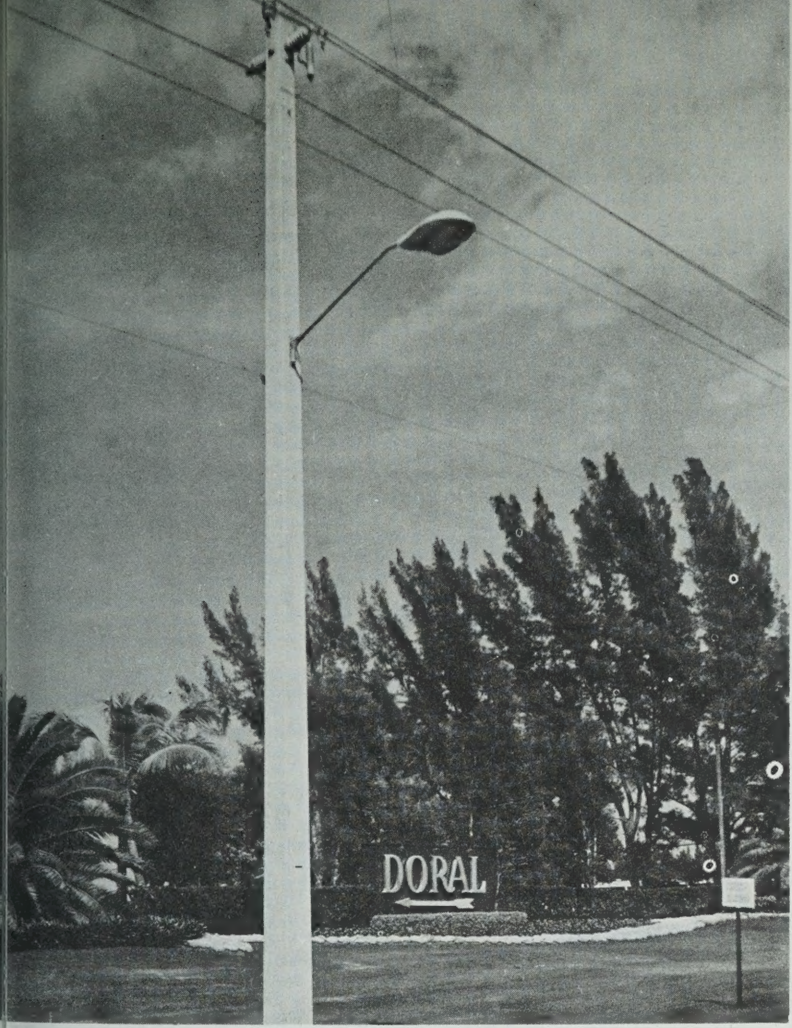


PATTERNS IN SUBSTATION BEAUTY

Various means are being utilized to harmonize substations with their surroundings. The most common is artful landscaping. Landscaping may be used to screen the station, as shown top left, by softening the lines, blending it into the neighborhood.

In other situations, architectural treatment such as decorative walls or complete buildings are necessary. Pre-fabricated concrete panels are used to form a wall around the substation at left. The finish and color of the panels can be varied.

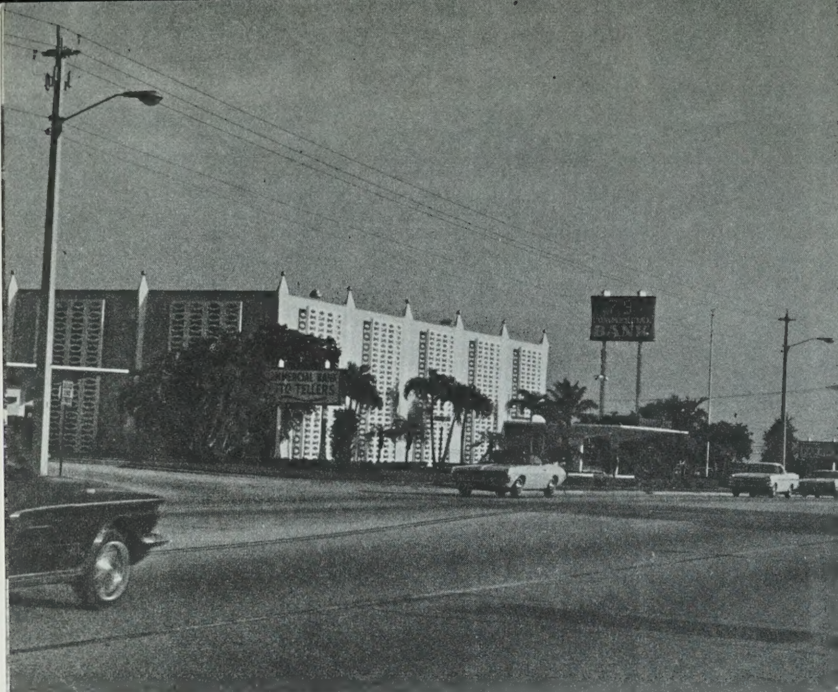
Decorative treatment, like those shown here, add significantly to the cost of substations and ultimately to the cost of electric service. In many locations, simpler measures meet the aesthetic requirements of the area and at a saving in cost to the customers.

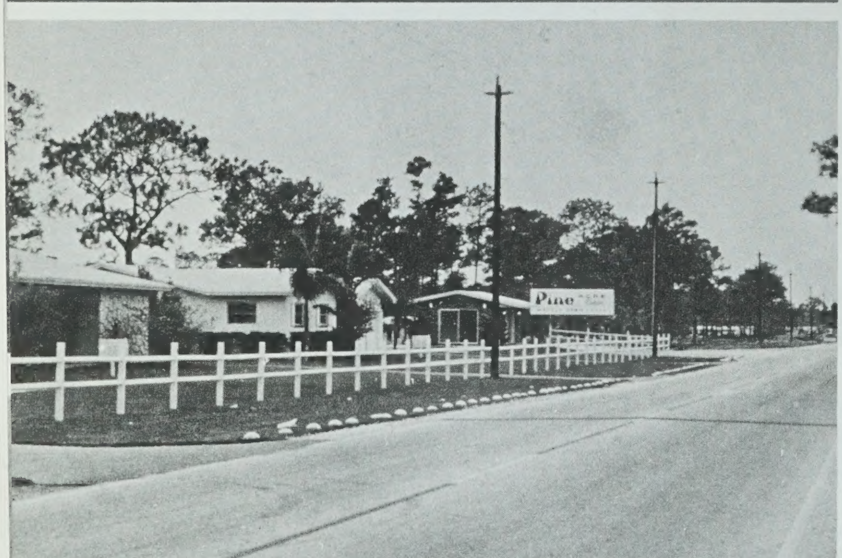


COLORFUL NEW DESIGNS IN POLES

The natural colored prestressed concrete pole, top left, supports a three phase primary feeder and a streetlight circuit. These poles are strong and durable as well as attractive.

The light green wood pole, at left, supports three phase primary with fiberglass pins. A new method of wood preservation permits painting or staining poles any desired color and eliminates later "bleeding" of the preservative.





TRIM NEW DESIGNS FOR LINES

A primary feeder through a commercial area, top left, uses "armless" construction on concrete poles. These poles also support the streetlights.

The three phase line in a residential area, center, features conventional wood poles and post-type insulators for construction. Compare the neat appearance of lines of this type to that shown below. This three phase line with streetlight and secondary circuits is typical of the older construction using crossarms for both the primary and streetlight circuits. Pole line silhouettes are much improved by elimination of cross arms and reduction in number of wires attached.

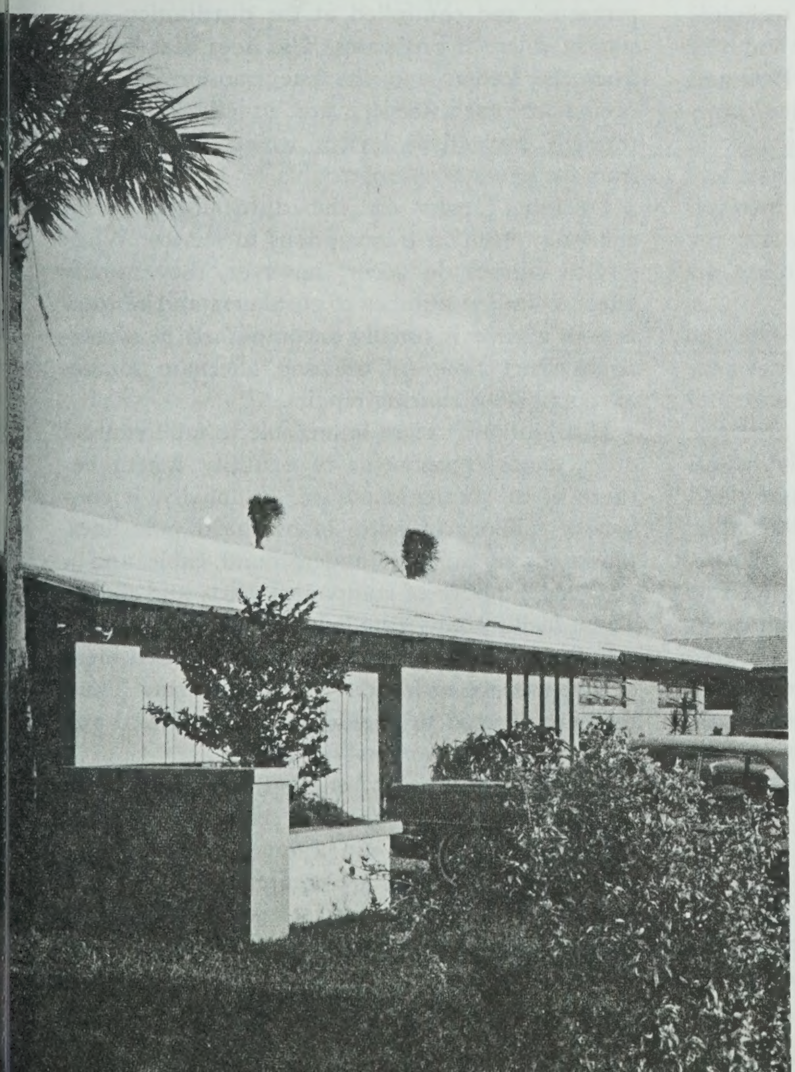
ENCLOSURES IMPROVE APPEARANCES

A pole mounted transformer installation, shown top left, serves loads of moderate size.

Service is provided for this apartment by an enclosed transformer located on a concrete pad near the customers load center. Such enclosures can be completely screened by landscaping if desired. The transformer is connected to an overhead line by cable attached to the pole pictured at left. This type of installation eliminates large transformers, large service conductors and clutter from overhead lines.

SCREENING BLENDS BEAUTY, SERVICE

Overhead distribution can be routed along rear lot lines, as shown at top. In areas with trees, the lines are well screened and the street appearance is similar to that of an area served by an underground system. Overhead distribution along rear lot lines "disappear" in this residential area with wide streets and two story homes.



NEW TREND IN SERVICE

This subdivision with an underground distribution system is using direct burial cables and padmount transformers. The only visible portion of this type of system is the padmount transformer which can be shielded attractively with shrubbery.

Many other ideas are being developed throughout the country in response to the changing needs of the times. Although underground is playing an increasing role in distribution systems, overhead lines will continue to have a rightful place for some time to come.

In many instances improvements in the appearance of both new and existing substations can be obtained at nominal cost by use of landscaping and color treatment. The use of extensive architectural treatment, such as complete enclosures, increases the cost of substations by very substantial amounts. Since the costs of environmental improvements are eventually reflected in the cost of service to all customers, a proper balance must be maintained between cost and aesthetic treatment of each substation.

SECTION 4—QUALITY OF SERVICE

The principal criteria for the performance of distribution systems are service reliability and voltage control, which together determine the quality of service received by customers.

Reliability

The ever growing use of electric energy in turn generates an increasing dependence upon the reliability or availability of electric service. Historically, the electric industry has met the need for increasing reliability. There are no technical barriers foreseen that would prevent the industry from continuing to meet this need until 1990 and beyond. The reliability of electric service, however, is controlled principally by economics. It is technically possible today to achieve almost any degree of service reliability, but the costs involved dictate the adoption of a level suitable for the customer's needs rather than the maximum attainable level.

Service reliability requirements vary with the nature of the load and area being served. A very high degree of reliability is considered essential for metropolitan downtown areas since a service interruption in these locations adversely affects large groups of individuals and businesses, and continuous operation of elevators and other public facilities is essential. Fortunately, the load density of these areas makes it economically feasible to provide a very high degree of reliability. A corresponding level of reliability is not economically justifiable in a low density residential or rural area. To attain such reliability would entail costs which most customers could not afford or would consider excessive for the improvement in reliability thus obtained.

Causes of Service Interruptions

On rare occasions, service to an entire city or large geographical area has been interrupted. These interruptions were caused by sequences of abnormal events or failures that related to major transmission and generation bulk supply systems. Most failures within these systems do not interrupt service.

Interruptions caused by distribution system failures occur more frequently but are usually confined to relatively small areas. Unlike the transmission system, which is a massive interconnected network, the distribution system consists largely of independent radial feeders, each supplying its own load area. Each feeder is individually protected and controlled at the distribution substation where it originates. The lines that branch from the feeder, and the line transformers connected to each feeder, are usually connected through protective devices which isolate them from the feeder in case of trouble.

Disabling faults on the distribution system generally result in interruptions to service. When service failures do occur, however, they usually affect a limited number of customers and restoration of service is usually accomplished in a relatively short time by utilizing alternate sources of supply or by making repairs.

Distribution is more vulnerable to failures than other major components of a utility system because of its greater exposure. Nationally, it consists of millions of miles of overhead pole lines, thousands of miles of underground cable and a countless number of component parts and pieces. These facilities are installed on streets, rear property lines, across meadows, through wooded areas or wherever necessary to serve all customers. Thus, they are exposed to a wide variety of natural and man-made environmental influences.

The largest number of distribution interruptions are caused by natural elements such as lightning, wind, ice and animals. Other major causes of interruptions are equipment failures and man-made causes such as vehicles hitting poles and excavation errors which damage buried facilities.

Reliability Measurements

One method of measuring reliability is by comparison of the customer-hours of service actually rendered to the customer-hours of service that would have been rendered if there had been no service interruption. The ratios developed by the application of these factors are in the order of 99.98 percent. These numbers are of value to the utility as a control and appraisal of its operating performance but are of little value as a measure of reliability from the individual customer's point of view. To him, the practical effect of an interruption of his service is the same whether or not the interruption also involves other customers. An infrequent short interruption may be acceptable to a residential customer, but quite serious to an industrial customer with continuous processes that require a long restart time. For this reason, meaningful conclusions cannot always be reached by comparing raw reliability statistics.

Overall national records of distribution service interruptions have not been accumulated. Individual utilities and groups of utilities keep records of their performance and make these available to regulatory commissions and other interested parties. Outage records provide numbers that are useful in comparisons of performance, but the degree of customer satisfaction is more meaningful than outage statistics.

Overhead Radial Circuits

The circuit arrangement that is generally used for distribution systems is classified as radial. A simplified diagram of a radial circuit is shown in Figure I-2.

In this arrangement, main primary feeders radiate from a substation to serve the surrounding area. Each feeder is connected to the substation through an automatically controlled circuit breaker. The remote ends of the main feeder

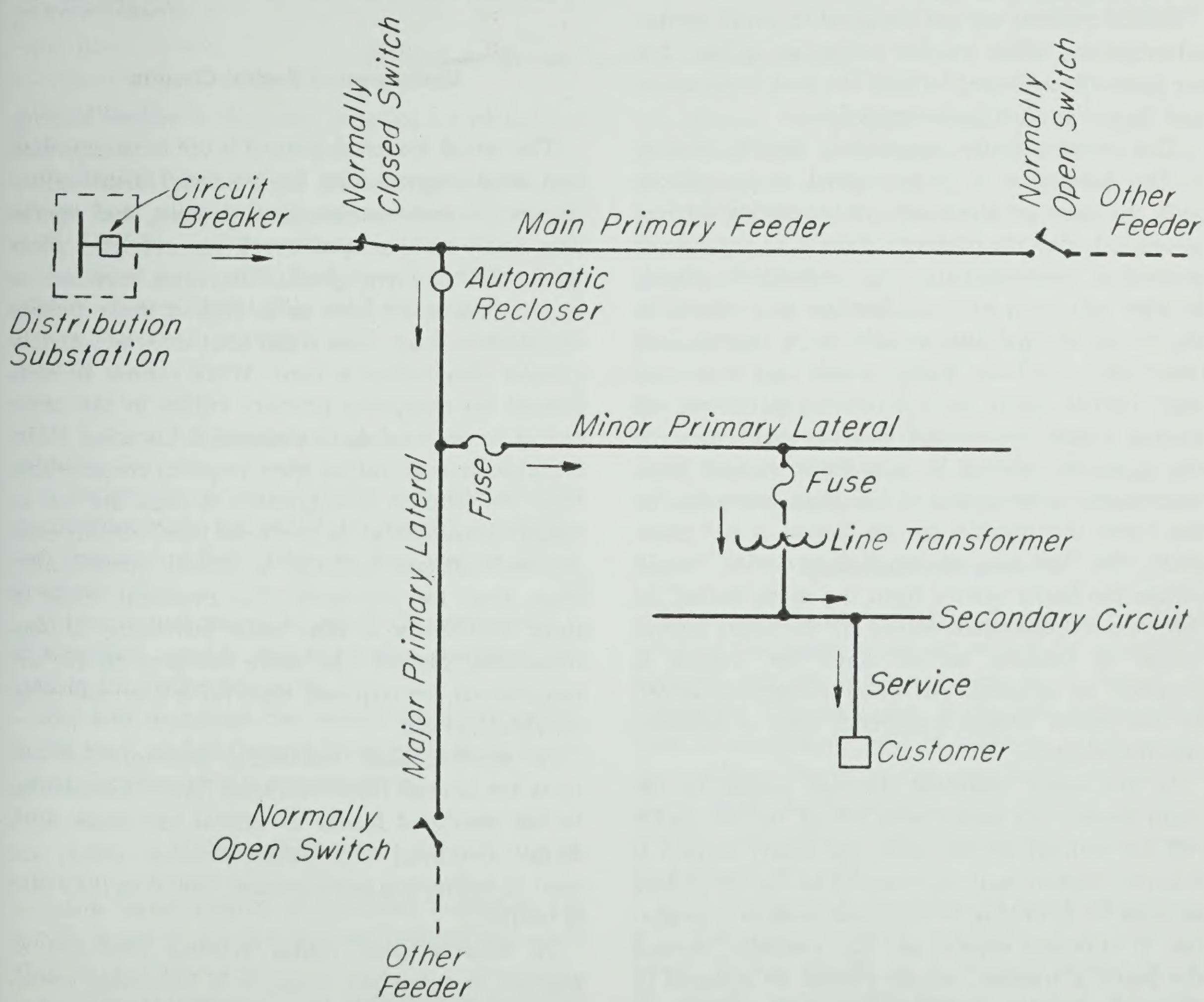


FIGURE I–2.—Schematic Diagram of Radial Distribution Feeder.

sometimes terminate in normally open switches to provide an alternative source of supply. Sectionalizing switches may be installed at intervals along the main feeder so that segments may be isolated to facilitate restoration of service following an outage or for maintenance of facilities. Laterals branch from the main feeder at intervals to serve the surrounding area. These laterals are usually connected to the main feeder through a fuse or automatic sectionalizing device. The laterals may in turn have a number of branches that are connected through fuses, switches or other sectionalizing devices.

In the vicinity of a customer or small group of customers, a line transformer is installed to reduce the voltage of the primary circuit to the voltage required by the customer. The line transformer usually has a fuse to isolate it from the primary circuit. A secondary circuit carries the power from the transformer to the service which is connected to the customer's wiring.

Radial systems are not designed to avoid service interruptions when trouble occurs on a line, but are generally arranged to limit the area interrupted and the duration of the interruption.

The automatically controlled circuit breaker at the substation is programmed to coordinate with the fuses or automatic sectionalizing devices associated with the primary laterals. In some fault protection arrangements, the substation circuit breaker will open within a fraction of a second in the event of disabling trouble on a lateral, and immediately reclose. If the trouble was of a transient nature, such as a lightning flashover, all service would be restored and the only effect to the customers served by this feeder would be a momentary interruption of less than a second. In the event the trouble on the lateral is not transient, the fuse or sectionalizing device would isolate the faulty lateral from the main feeder. In this case, the customers served by the faulty lateral would be without service until the trouble is repaired or isolated. All other customers served by the feeder would experience only a momentary interruption.

In the event disabling damage occurs to the main feeder, the entire area served by the feeder will be without service until the faulty section is isolated. Service may be restored to the remaining sections by switching to alternate sources if available. If alternate sources are not available beyond the point of trouble, service cannot be restored in the faulty section, and beyond, until repairs can be made.

Trouble on a secondary circuit or line transformer will normally open the fuse or circuit breaker at the transformer without disturbance to the remaining customers served by that feeder. The customers served by the secondary circuit or transformer in trouble will be without service until repairs are made or temporary measures taken to restore service.

Thus, the reliability of a radial system depends not only upon type of construction and exposure, but also upon such factors as the number of sectionalizing points, the number and location of alternate sources of supply, the arrangement and sectionalizing provisions of laterals, the time required to locate the trouble and to perform the necessary switching to isolate the faulted section, and the time required to make repairs. The effect of these factors will vary widely for different feeders, depending upon load density, geographical features, size of area served, and degree of exposure to possible sources of trouble.

Underground Radial Circuits

The radial system described is the most practical and satisfactory system for overhead distribution. Almost all construction, maintenance, and operation work can be performed on overhead lines while they are energized. The time required to locate trouble, perform switching, or make repairs is relatively short. This is not the case when underground distribution is used. Work cannot be performed on energized primary cables to the same extent as on overhead conductors. Locating faults on underground cables often requires considerable time. Switches in underground systems are not as readily accessible as on overhead lines. Repair time for underground facilities is usually considerably more than for overhead. The practical result of these differences is that more switching or sectionalizing devices and more complex circuit arrangements are required than for a corresponding overhead system.

At present, most residential underground systems are laterals from overhead lines. Connections to the overhead feeder or lateral are made with simple overhead type fused switches which are used to isolate the underground lateral in the event of trouble.

As underground radial systems continue to expand in suburban areas, it is becoming necessary to install main feeders underground. Need for adequate sectionalizing devices for the under-

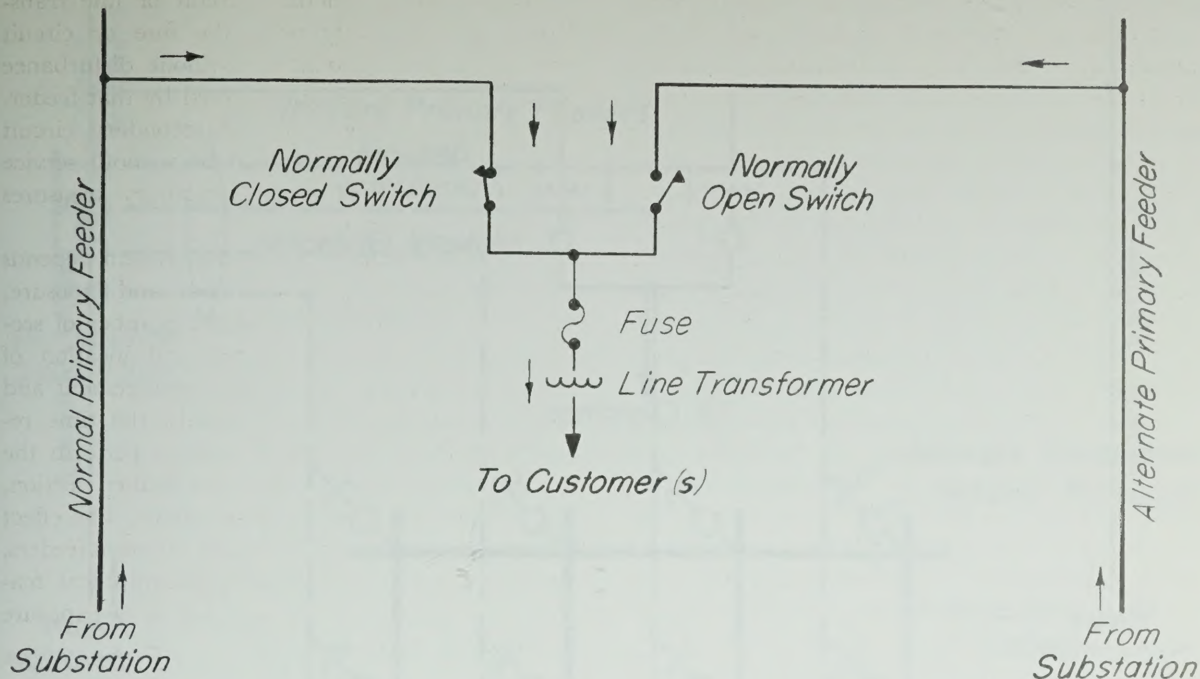


FIGURE I-3.—Primary Automatic Transfer Scheme.

ground feeders is discussed in following sections of this report.

Customers served from an underground radial system will probably experience fewer interruptions, but of longer duration than if they had been served from an overhead radial system. Over a long period, there is likely to be little difference between systems in the total time that service is available.

Automatic Transfer

A higher degree of reliability can be provided to specific loads on radial feeders by extending two separate radial feeders to the load as shown in Figure I-3.

If the normal source of supply is interrupted, a mechanized switch automatically transfers the load to the alternate source.

The cost to extend the second source of supply to the load, and of the switching equipment, limits the application of this arrangement.

Spot Networks

A still higher degree of reliability is possible for specific loads by use of a spot network arrangement as shown in Figure I-4.

In this arrangement, the customer is supplied from two transformers, each connected to a different feeder from the same substation. Each transformer has sufficient capacity to supply the total load and is connected to the load through an automatic switch known as a network protector. In the event of failure of either a transformer or the primary feeder supplying it, the network protector will open automatically to disconnect it from the load and uninterrupted service will be maintained from the remaining feeder. Spot networks may be supplied by more than two feeders if required by the magnitude of the load. This type of service is more costly than the automatic transfer scheme since duplicate transformers as well as duplicate feeders must be provided.

Secondary Networks

Many of the high density downtown business areas of the larger cities are served by secondary network systems. Such a system is illustrated in Figure I-5. The customers in the area are supplied from a network or grid of interconnected secondary cables. Power to the grid flows by parallel paths from the substation over several primary feeders and through the transformers connected to the secondary grid.

Each transformer is connected to the secondary grid through a network protector. If a fault or power failure occurs on a primary feeder or in any of the transformers connected to it, the network protectors on all of the transformers supplied from that feeder will open. All of the customers

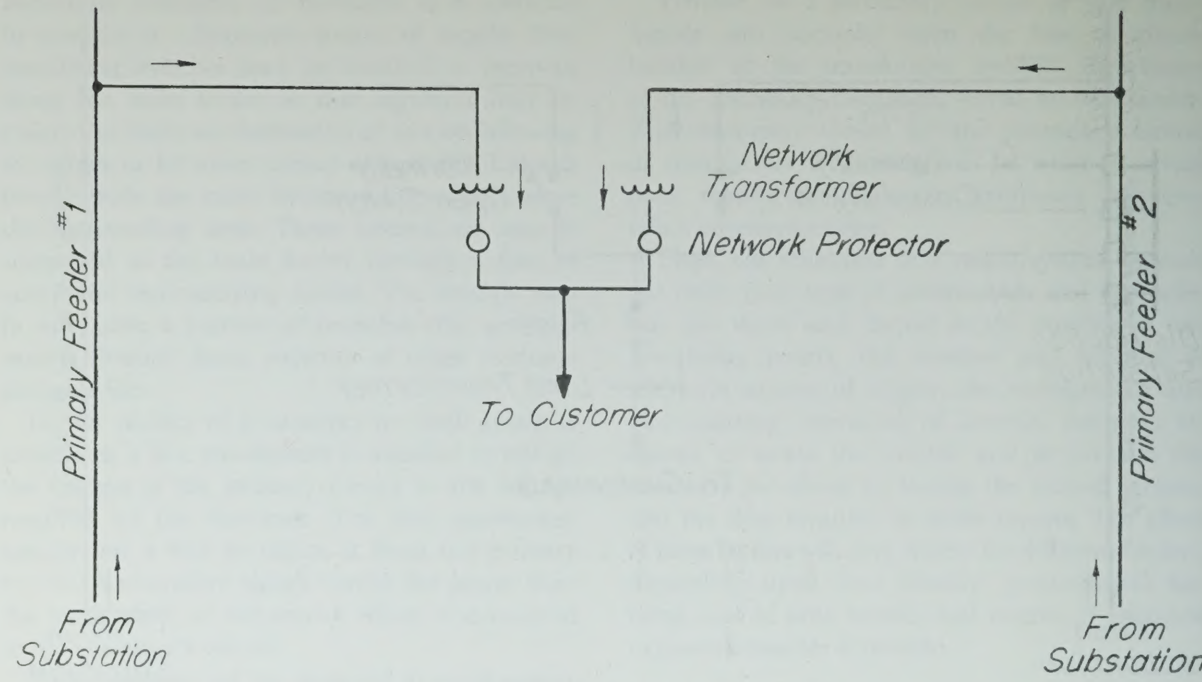


FIGURE I–4.—2-Feeder Spot Network.

served from the grid will then continue to receive uninterrupted service from the remaining feeders and their associated transformers.

A fault on a secondary cable in the grid will normally be cleared by fuses or will burn itself clear without interrupting service except to the customer or customers connected directly to the faulted section of cable.

Summary of Circuit Arrangements

It is apparent that by circuit arrangements it is technically possible to provide various degrees of service reliability. The practical problem is to achieve a balance in which satisfactory reliability is provided at a reasonable cost.

Operating Procedures

The almost universal use of radio to dispatch personnel quickly to points of trouble has been an important factor in reducing the duration of interruptions of distribution circuits. In the larger cities, rather elaborate systems have been developed to receive and process quickly the many customer calls that are received when an interruption occurs to a large area. As systems grow, further improvements in procedures and added facilities for handling large numbers of calls will be needed.

Many utilities have computer programs to analyze reports of interruptions to determine the performance of each circuit and the principal causes of interruptions. These analyses provide a sound basis for changes in practices or materials to reduce the number of interruptions.

Computer programs to calculate customer and transformer kW demands from customers kWh records are available. This provides a reliable and quick method to check the loading of all distribution transformers and helps avoid failures from overloads.

Adequate tree trimming programs are essential to good service in areas where overhead lines are located close to trees. Utilities use specially trained personnel for this work and are active in the International Shade Tree Conference and in regional tree organizations. They also contribute to the development of master tree plans and the publication of tree guide books. These programs have as their objective, better service reliability in a better appearing community where trees and electric utility lines are compatible.

Increased use is being made of small trailer-mounted transformers with associated cable sections to permit quick substitution for failed units, either overhead or underground. These portable transformers are used to facilitate replacement of in-service transformers with a minimum of service interruption time.

The use of hot-line tools and aerial lift devices has increased the capabilitity of performing work on overhead systems without interrupting service.

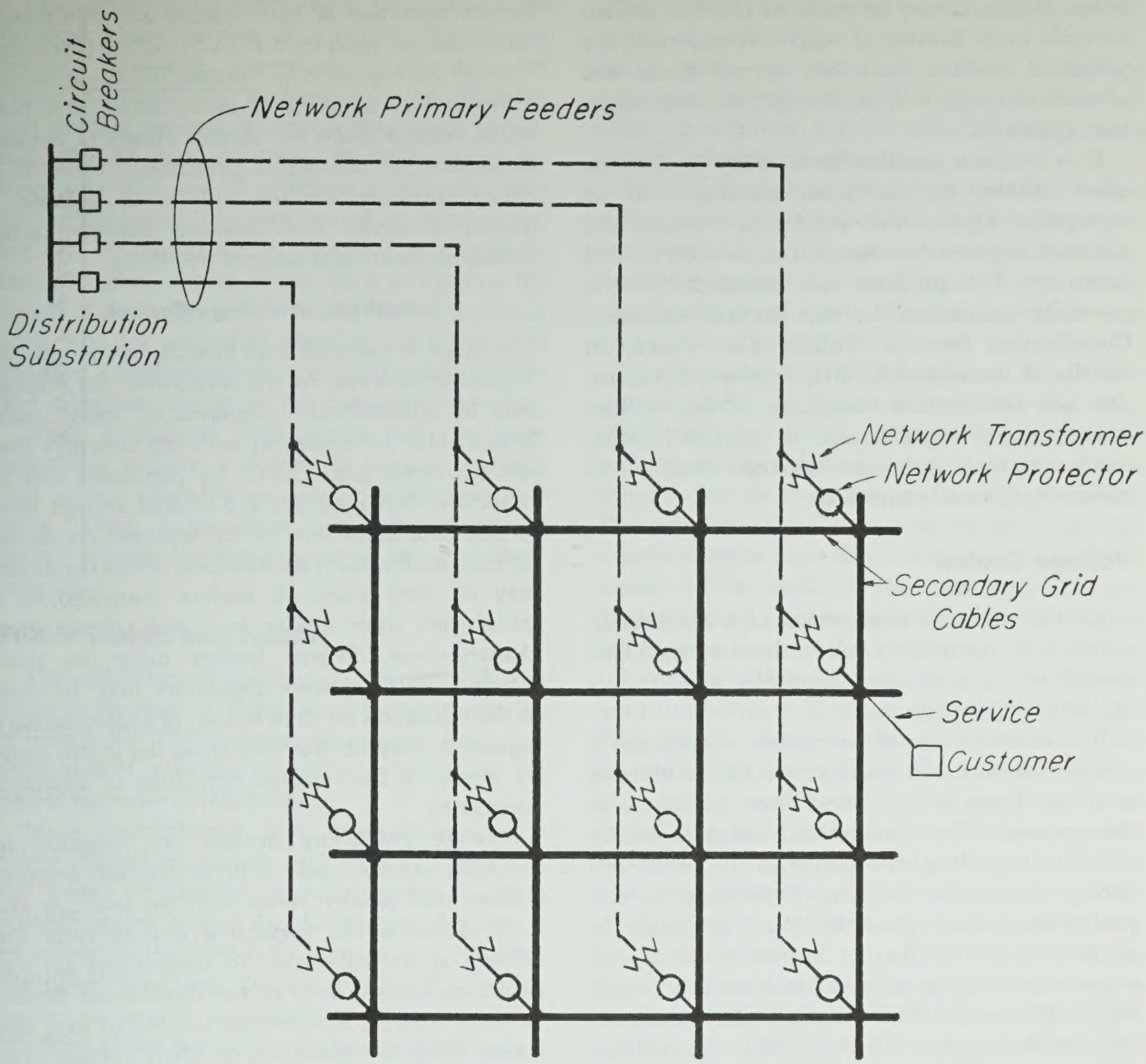


FIGURE I–5.—4-Feeder Secondary Network System.

Storm Procedures

Overhead lines of modern design and construction are considerably less susceptible to storms than their predecessors. However, it is not economically feasible to build distribution lines to withstand the occasional very severe storm without damage. The alternative is to provide the organization and facilities necessary to locate and repair the damage quickly.

An effective service restoration program incorporates accurate weather forecasting so that personnel and equipment, in the quantities required, are made available for immediate response. A principal source of weather information is the Environmental Science Services Administration. In addition, many utilities have full-time meteorologists and others use private consultants for their special requirements. Several utilities have weather radar installations and other special devices such as lightning stroke counters to enhance their ability to forecast local conditions.

A group of 46 utilities located in the eastern part of the country has developed a procedure for relaying weather and utility damage information over the normal channels of communications between companies. This procedure provides information to assist utilities in tracking a storm and estimating its potential effect on their facilities.

Most utilities have one or more emergency plans designed to cope with severe storm damage. These plans provide for personnel organization and for procedures, and equipment tailored specifically to facilitate service restoration following such a

storm. Provision may be made for effective utilization of a large number of supplementary company personnel diverted from their normal duties and of workmen who may be brought in from neighboring utilities.

It is common practice for a utility to draw on other utilities for additional manpower in an emergency. Eighty-three utilities have joined into a formal organization designed to provide mutual assistance. This program was established and is currently maintained by the Mutual Assistance Coordination Between Utilities Task Force, an activity of the Edison Electric Institute Transmission and Distribution Committee. Other utilities have regional organizations to provide mutual assistance. Such assistance has been readily and effectively given when needed.

Voltage Control

Another essential requirement of a distribution system is to maintain a voltage level at each customer's service that is within suitable limits for his utilization equipment.

It is characteristic of an electric system that a voltage loss occurs in transformers and conductors as power flows through them from the source to the customer. This voltage loss, which is usually called voltage drop, also occurs in the customer's wiring system. The amount of the drop in any part of the system is proportional to the magnitude of the load current flowing through it. As a consequence, the voltage close to the source is normally higher than at locations remote from the source. Because the current flow and hence the voltage drop varies with the season and time of day, the voltage at any particular location is also subject to variation. For these reasons, it is not economically feasible to supply each customer with a constant voltage corresponding exactly to the rated voltage of his utilization equipment.

A compromise is necessary to provide for both the inherent characteristics of the electric supply system and the voltage requirements of the customer's equipment. If the range of the supply voltage were too great, the cost of appliances and equipment would be greater because they would be required to operate satisfactorily at any voltage within the range. On the other hand, if the supply voltage limits were restricted to a narrow range, the cost of providing the power would be unduly high.

The compromise that has evolved over the past years has proven to be practicable. Preferred voltage levels and ranges of variation for satisfactory operation of both systems and equipment have been set forth by a USA Standard (Preferred Voltage Ratings for A.C. Systems and Equipment).

Regulatory agencies of many states also prescribe voltage limits for various classes of service. Regardless of the limits prescribed, there is a strong incentive for the utilities to provide a quality of service that promotes customer satisfaction and increased usage of electricity.

Methods of Voltage Control

Voltage is controlled on distribution systems in a number of ways. At the substation, the voltage may be automatically regulated by using transformers that are equipped with tap changers that operate under load (LTC) by regulators and/or capacitors that maintain the desired voltage level on the substation bus, or by separate regulators for each feeder. LTC transformers or bus regulators may be used when all feeders connected to a transformer have similar load and voltage drop characteristics. Where feeders differ in these characteristics, separate regulators may be used in the substation for each feeder, or supplementary regulation may be provided along the feeder route by means of line voltage regulators or switched capacitors.

Voltage regulating devices are designed to maintain automatically a predetermined level of voltage that usually varies with the load. As the load increases, the regulating devices raise the voltage at the substation to compensate for the increased voltage drop in the distribution feeder. In cases where customers are located at long distances from the substation or where voltage drop along the primary circuit is high, additional regulators or capacitors at selected points in the line provide supplementary regulation.

Use is made of shunt capacitors in substations and on primary circuits for the dual purpose of improving power factor and regulating voltage. Many of these installations have sophisticated controls designed to fulfill either or both purposes by automatic switching. In some instances, automatically switched capacitors have entirely replaced conventional step or induction regulators for control of voltage on distribution feeders.

Heat dissipation problems and high cost of switching equipment limit the application of capacitors on underground circuits. Thus it is expected that there will be some limitations to the use of capacitors for voltage regulation on such circuits until such a time as the economic and technical problems associated with underground installations can be overcome.

Occasional momentary dips in voltage are inherent characteristics of a power distribution system. Switching operations, faults that are cleared automatically by fuses or circuit breakers, and starting currents of motors may result in voltage dips of short duration. If these dips occur frequently and are of sufficient magnitude, they can be annoying. The dips caused by motor starting can be minimized by proper motor application and good circuit design, such as limiting the length of secondary circuits, use of cable in lieu of open wire for secondary circuits, use of low impedance transformers on the distribution circuit, and adequate wiring on the customers' premises.

Some specialized installations such as large computers require a degree of voltage stability that is not available on power distribution systems. These applications may require special energy storage systems located on the customers' premises.

Future Trends and Needs

The reliability of distribution systems will continue to increase in response to the requirements of customers. The expected increase in load densities should provide economic support for expected increases in reliability.

More sophisticated bus arrangements, and better protective devices and control systems in the larger substations should provide a more reliable power source for distribution feeders. A most challenging need is for automatic or remotely controlled switching devices on the distribution feeders to provide immediate isolation and identification of the faulted line section and restoration of service to the remainder of the circuit. Considerable development work will be required to produce switchgear, communication channels and logic controls that are economically feasible for general application on underground and overhead circuits.

Experimental installations are being made on distribution systems to remotely monitor each customer's service or individual component such as a line transformer. Such a system would provide immediate notice of a local service failure or abnormal voltage or load condition. An automatic entry of this data into an on-line computer would provide the data for a quick analysis of the extent of trouble. The location of the fuse or isolating device that operated could be pinpointed and the information to facilitate quick restoration could be obtained without depending upon calls from customers without service.

It is likely that in the future practical means will be available to provide remote monitoring of each customer's service and each line transformer, remote reading of each customer's meter, and remote operation of distribution line switches over a common communications channel.

The extensive use of underground distribution anticipated for the future will produce new reliability problems. In an effort to reduce the cost and extend the application of underground distribution, many new concepts are being applied. The rapidity of the change to underground distribution leaves scant time for equipment developments. While most of the new concepts and designs should operate satisfactorily, high failure rates may occur in some cases.

Lightning will continue to be a source of overhead line outages in many parts of the country. The general trend is toward higher insulation levels for distribution circuits and the application of lightning arresters or overhead ground wires for lightning protection. Performance has improved accordingly. Optimum designs are somewhat hampered, however, by the meager knowledge of lightning stroke frequency and characteristics for particular service areas. The only nationwide data available that relates to stroke frequency are the isokeraunic levels (thunderstorm days) published by the U.S. Department of Commerce. The number of thunderstorm days is not an adequate base for optimum design of lightning protection. Several countries in Europe have, for a number of years, collected and published stroke frequency data accumulated by means of electronic counters. A similar practice for this country would be beneficial.

Mathematical models are being developed to evaluate the effect of various arrangements on the overall reliability of distribution systems. Continued development of such models should provide distribution engineers with more precise methods for improving reliability.

SECTION 5—GOVERNMENT REGULATION

The Electric Utility Industry is subject to the jurisdiction of various regulatory authorities at local, state and federal levels. The primary regulatory authority for the investor-owned electric utility is the State Utility Commission, although, insofar as distribution systems are concerned, there

are many local requirements. Forty-seven of the fifty-three State Utility Regulatory Commissions have authority to carry out important regulatory functions governing the activities of the investor-owned electric utilities. A much smaller number of these commissions also have varying degrees of jurisdiction over the publicly owned utilities. The Federal Power Commission is more directly concerned with generation and transmission than with distribution. A number of other federal agencies are directly or indirectly involved with the distribution function in varying degrees. Included among the various requirements by the local, state and federal authorities are accounting, data reporting, rate and rule making, service performance and related codes.

Accounting

The Federal Power Commission prescribes a Uniform System of Accounts for Public Utilities and Licensees as defined in the Federal Power Act. The Act provides, however, that this shall not relieve any public utility from keeping any accounts, memoranda, or records which such public utility may be required to keep by or under authority of the laws of any state. The system of accounts also applies to agencies of the United States engaged in the generation and sale of electric energy for ultimate distribution to the public, so far as may be practicable, in accordance with applicable statutes.

Changes in the Uniform System of Accounts are ordinarily accomplished by FPC rulemaking and are coordinated with the accounting committee of the National Association of Regulatory Utility Commissioners.

One of the subjects being reviewed which has considerable significance in connection with the utilities' underground programs is that of modifications in the accounting for contributions in aid of construction. Substantial increases in this account have come about through extensions of utility facilities and the increasing use of underground distribution.

The regulatory authorities at all levels should give careful consideration to the initiation and development of proper methods for the allocation of costs relating to aesthetics. Balance is required between economics, service, safety and aesthetic considerations in future system planning and design. Specific attention should be given to the establishment of a uniform and more informative accounting procedure for underground distribution.

Data Reporting

In addition to annual financial reports, the FPC requires monthly financial and statistical reports and annual statistical reports.

State bodies usually require the same information as is required at the federal level. In addition, many of the state commissions require advance submission of budgets for capital expenditures and pertinent data closely related to distribution, such as meter tests, interruptions to service reports, etc.

State Requirements

The state utility regulatory commissions have authority of varying extent to regulate rates of sales to electric customers. Nearly all of the commissions have complete authority over the rates to be charged ultimate customers served by investor-owned utilities, but only a relatively few over the rates of publicly-owned utilities. (Most publicly-owned utilities are responsible to an elected body.) Most state commissions have authority to regulate rates of investor-owned utilities who supply power to public authorities and the United States Government.

General procedures for the establishment of rates include an analysis of the reasonableness of the operating costs of the utility, together with the development of reasonable depreciation charges and rate base. The rate base is related to the depreciated cost of utility property and to the utilities' investment. An element in establishing rates is the determination of a fair rate of return that the utility should be allowed the opportunity to earn on its rate base.

For rate-making purposes, electric utilities divide their customers into broad categories having similar use characteristics, such as residential service, small general use, large general use, street lighting service, and large water pumping service. Some utilities serving important loads with specific use characteristics, such as oil field pumping, irrigation pumping, or metal melting furnaces may design a special rate (class rate) to fit the use pattern of such loads, and to encourage their maximum use during the hours when system demands are at a minimum. Some utilities also make use of zone rates for domestic and small commercial customers to reflect the difference in

cost of service due to customer or load density and other factors.

An important part of the state commission's rate-making authority is the establishment of rules covering the description of service and the basis of expanding service. Extension rules for overhead service are usually designed to permit and encourage the expansion of service. Extensions of underground systems have been based on a variety of practices, the most prevalent of which has been the "difference in cost" principle. Under this principle, the customer, developer, or applicant for service is required to pay the difference between the estimated cost of an equivalent overhead system and the cost of the installed underground system as a contribution in aid of construction. As the cost differential between overhead and underground construction has been reduced, there has been a tendency for some utilities to absorb a portion of this difference in order to promote underground distribution as their standard service for new residential developments. In some areas, special consideration is given to the heavy electrical use homes. In some cases, service from underground systems is provided on a higher rate level basis.

Some state commissions have taken action to approve new rules or promulgate uniform rules covering extensions of underground systems or conversions of overhead lines to underground. Other state commissions are currently reviewing or will review practices for new underground construction and conversions. Illustrations of state commission action are described in the following paragraphs.

The Utility Commission of the State of Maryland has issued rules requiring underground extensions to serve new residential sub-divisions. This commission has recommended similar rules requiring underground service to new commercial and light industrial customers. Recognizing the high cost of conversion and the difficulty of financing, the Maryland Commission staff recommended that the commission rule only on the portion of the conversion cost which must be borne by the utilities. The staff report of August 1968 indicated that a substantial portion of the cost of conversion must be funded by means outside of normal utility financing channels.

The State of California has adopted a rule regarding the conversion of overhead distribution facilities to underground. The California Public Utilities Commission ordered the utilities to file a new statewide conversion rule in September 1967, which in essence requires the utilities to budget annually a specific amount of money to be spent for the conversion of overhead distribution plant to underground. The budgeted dollars are allocated to each city and the unincorporated area of each county in proportion to the number of customers in each area compared to the total customers served. The amounts appropriated annually for an area may be carried over and accumulated in order to finance a project whose cost totals more than one year's allotment. The areas to be converted are determined by the governing body of the city or county after consultation with the utility. Such undergrounding must be in the public interest and the city or county is required to adopt an underground ordinance applying thereto. In other circumstances, the utility may convert its overhead facilities to underground upon mutual agreement with applicants if property owners agree to make service wiring changes to accept underground, perform all trenching, backfilling and repaving, furnish and install all substructures and conduit, and pay the excess cost of the underground system over the estimated cost of an equivalent new overhead system. In all cases, there must be agreement for the removal of all existing overhead communication and electric distribution facilities within the area to be converted.

Real estate developers who operate in different states and individuals who move from one area to another find it difficult to understand why underground practices differ so much. There seems to be general agreement and acceptance that underground distribution improves the appearance if used in lieu of overhead, that new underground costs more than equivalent overhead, and that the cost of conversions is several times that of the overhead replaced. Uniform rules are desirable to encourage underground service where underground installations are economically feasible. Where differing rules are adopted to be compatible with local conditions adequate information should be provided to all interested parties.

Adequacy of Service and Maintenance Practices

In nearly all states, commissions having the authority to regulate rates for electric utilities also have authority to establish service and construction standards. National codes and United States of America Standards Institute (USASI) standards comprise the basis for most state requirements regarding the design and construc-

tion. Many states provide for inspection of construction material, methods of construction, and cost justification for completed projects. Meter accuracy limits and the frequency of meter reading, customer billing, and meter testing are important responsibilities of the utilities that are directed by the state commissions. Maintenance practices, frequency of inspection and patrol, and practices pertaining to chemical control of right of way and roadside brush control are often major areas of concern by state agencies. Some of the agencies in the states responsible for these controls are Department of Labor, Bureau of Weights and Measures, Department of Public Safety, Department of Public Works, Department of Natural Resources, State Fire Marshals, and Civil Defense.

Local Requirements

Municipalities exercise a varying degree of control over distribution practices through franchise regulations, zoning ordinances, and building permit policies.

The franchise usually outlines the obligations, rights and responsibilities of the electric utility in the community which it serves. When used as a regulatory device in the absence of state regulation, the franchise contains provisions concerning rates and service standards. When used as a supplement to state regulation, it is often a grant of authority of the utility to occupy or use city streets and alleys. Certain conditions are imposed with this grant, such as location of facilities, responsibilities for street repairs and certain payments to the city.

Municipal zoning ordinances requiring plans to chart the future land use patterns as a community grows, are becoming commonplace. Many local communities have active zoning laws that specify the land uses which will be permitted in each zone. These laws can aid the electric utilities if they provide for planning of the expansion of service throughout the areas served. On the other hand, some zoning laws hinder the utilities and adversely affect the quality of service received by the customers by unduly restricting locations of distribution lines and substations within specific areas. Many of them do not state clearly that substations and the associated distribution and transmission lines may be located within these future growth areas.

Building permits are required at the local level in order to insure that zoning laws and building codes are not violated. A building permit is generally required for any new construction and reconstruction on land covered by zoning laws. It has been customary to invoke only minimum requirements for utility permits because the utility is a permanent part of the community and is responsible for the maintenance of the installed facilities during their lifetime. The trend to high-rise buildings will require the utilities to install and be responsible for their facilities within the confines of these buildings. There is need, therefore, to review building permit policies to be sure that obsolete permit requirements do not unnecessarily restrict utility operations to the detriment of the customers' interests.

Codes

In almost all states, the regulatory commissions have the authority to establish safety codes for the investor-owned electric utilities and, to a lesser extent, for the publicly-owned and cooperative utilities. Most states have based their rules for overhead and underground electric line contruction on the National Electrical Safety Code, which is the national standard for installation and maintenance requirements for electrical utilities. This code was originally developed in 1916. The latest (sixth) edition was published in November of 1961. Supplement No. 2 defines the requirements for modern underground distribution with power and telephone cables installed with no deliberate (random) separation. This code constitutes the basis for most state requirements. However, some states have developed more stringent rules governing the safety of overhead and underground electric line construction.

Some municipalities have passed ordinances requiring new residential subdivisions to be supplied by underground distribution and have attempted to require the conversion of some overhead facilities to underground. In some cases, underground line construction requirements more restrictive than those of the National Electrical Safety Code have been promulgated by local governments. These restrictions, when enacted without full knowledge or consideration of the associated costs or the availability of adequate equipment may have a significant economic impact on the cost of service to the customer and an adverse effect on progress toward the goal they are trying to achieve—underground distribution.

The National Electrical Code was originated

in 1897 by a national conference on standard electrical rules. The code is revised at three-year intervals and the currently adopted and approved edition was published in 1968. The National Electrical Code covers requirements for customer-owned electrical facilities. It has achieved almost universal acceptance and forms the basis for nearly all the electrical ordinances of governing bodies. Electric construction costs are directly affected by the Code. It is very important that the NEC Committee members be cognizant of the rapid changes that are occurring in the distribution field, particularly with regard to new products, equipment and methods of installation. New developments that are in the public interest should be recognized in Code revisions.

A very rapid growth in electric loads coupled with the emphasis on aesthetics and on new types of underground electric systems necessitates an imaginative approach for regulations and codes. Rules adopted at the state level pertaining to utility-owned electric systems, and changes made in codes at the local level pertaining to customer-owned electric systems should be compatible with the rapidly-changing electric distribution technology.

Federal Agencies Other Than FPC

Many of the state agencies adopt their policies and procedures from similar agencies operating at the federal level. The federal agencies that have an important impact on the utilities' cost are discussed in the following paragraphs. Each of the agencies described may, and in fact does, modify or interpret its own regulations. It is easily seen that the control and regulation exercised by these agencies can have a substantial impact on the cost of electric service.

These agencies, in making decisions affecting electric distribution, should give full consideration to all the criteria that distribution systems must meet. Restrictions on location, design or installation of facilities that would unnecessarily increase costs, delay service to customers, or impair service reliability should be avoided.

Bureau of Public Roads, Federal Highway Administration, U.S. Department of Transportation

The Bureau of Public Roads prescribes the policies and procedures for accommodating utility facilities on the rights-of-way of federal and federal-aid highway projects. The Bureau's Regional Administrator is given powers to control and regulate the use by utilities of the rights-of-way of federal highway projects.

Department of Interior and Forest Service

Right-of-way easements for electric power transmission and distribution lines on or across lands controlled by the Department of Agriculture, including national forest lands, are controlled and issued by the Forest Service. Those over the public domain, national parks and national monuments and other Department of the Interior agencies are issued by that department. Easements are generally limited to not over 50 years, and contain provisions to protect the public interest and safety as well as conserving recreational, scenic and aesthetic values. Special requirements may be incorporated as appropriate.

Federal Aviation Administration

Construction of distribution facilities at or near airports is controlled by the Federal Aviation Administration (FAA) as authorized by the Federal Aviation Act of 1958. The FAA has established regulations requiring that proposed new construction or alterations which might be considered an obstruction in navigable airspace be reported to the FAA Administrator for approval (Part 77 of Chapter I of Title 14 of the Code of Federal Regulations). Included in these regulations are standards for determining obstructions in navigable airspace. The standards are designed to accommodate various classes of airports.

Considerable reconstruction of electric distribution facilities may be required when an airport increases its size, adds another runway or is reclassified by the FAA.

Federal Housing Administration, U.S. Department of Housing and Urban Development

Undergrounding of electric utilities in new housing developments has been adopted by the Federal Housing Administration (FHA) as a criterion for underwriting home mortgages. In 1965, the FHA administrator advised all regional offices that underground electrical distribution systems would be required in all new subdivisions (including planned-unit developments) unless such an installation is demonstrated, to the satisfaction of the Regional Administrator, to be impractical or economically unfeasible. Substantially, this requirement has been included in the FHA Underwriting Manual, Section 71650.

PART II—DISTRIBUTION TECHNOLOGY

The principal components of an electric distribution system are distribution substations and overhead and underground lines. Directly related to these components are engineering and construction techniques and research and development. These subjects will be discussed in this part of the report.

The principal criteria for the performance of distribution systems are service reliability and voltage control, which together determine the quality of service received by customers. Quality of service was discussed in Part I, Section 4. Its relation to the technical aspects of each major system component is further considered in this part of the report.

SECTION 1—DISTRIBUTION SUBSTATIONS

Distribution substations are the links between the high voltage transmission lines and the lower voltage distribution circuits. The basic substation function is to receive power from the high voltage transmission system and convert it to a voltage level suitable for local distribution circuits. Substations vary in size and complexity from a simple arrangement supplying one distribution circuit to highly automated, elaborate stations supplying many distribution circuits. In most cases, substations include provisions for voltage regulation to maintain automatically within specified limits the voltage delivered to the distribution circuits.

Distribution substations contain switching equipment to isolate a faulted circuit or transformer automatically from the remainder of the system. They are often used as sectionalizing points on the transmission system to permit the isolation of trouble on those lines. From the substation distribution circuits radiate to serve the surrounding area.

Substation Components

The principal components of a distribution substation are high and low voltage switching equipment and transformers, which are discussed in the following subsections.

High Voltage Switching Equipment

High voltage switches, circuit breakers, and associated controls are necessary for system operation, the detection of abnormalities, and the rapid isolation of faulted segments of the system. In the event of trouble on the transmission system, automatic operations are completed within extremely short intervals (fractions of a second). Detailed technical analysis of these operations enables the industry to continually improve the performance of the system.

Substation Transformers

Distribution substation transformers, which change the high transmission voltage to the distribution voltage level, provide the electrical connection between the transmission and distribution systems. Such transformers are among the more reliable components of the entire system. The following factors contribute to this high reliability.

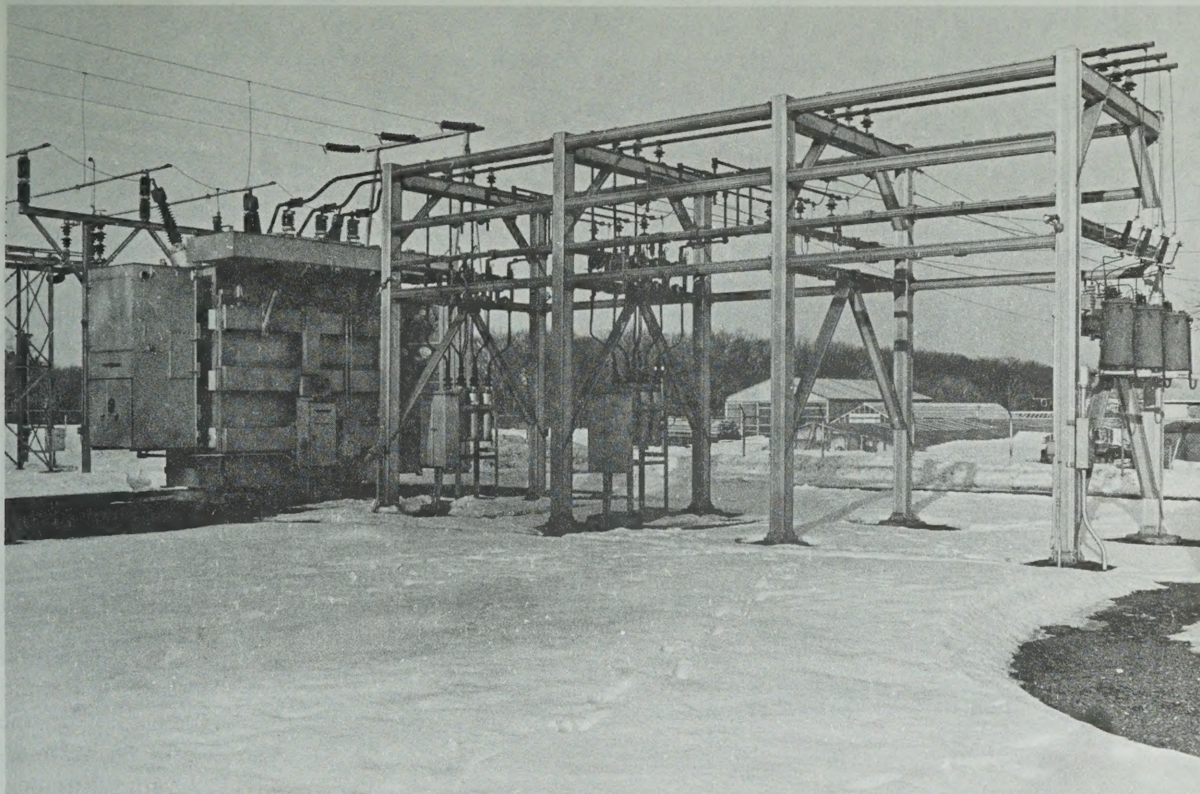
The basic transformer does not have moving parts.

The electric windings are isolated and oil-immersed within a steel tank, usually under positive pressure of inert gas to prevent the possible intake of moisture and contamination of the insulating oil.

The units are protected from lightning when necessary by arrestors on both the high and low voltage sides.

Transformers are subjected to rigorous inspection and maintenance programs to detect trouble before failure in service.

Faults in substation transformers may affect all the customers served from the substation. This



Open-Type Switching Equipment.

effect may be only a momentary drop in voltage or it may be an interruption of service for a few hours, depending on the nature of the trouble and the system arrangement. In urban areas, substation transformer failures may not result in longer than momentary outages to customers.

Distribution substation transformer capacity reported in service at the end of 1967, for Class A and Class B investor-owned utilities, totaled 243.8 million kVa or 4.6 kVa per customer. This is an increase in substation transformer capacity of 119 million kVa or 95 percent for the preceding 10 year period. For this same decade, substation transformer capacity per customer increased 1.73 kVa or 61 percent. Continued increase at the same rate would result in 1.16 billion kVa of substation transformer capacity for Class A and Class B utilities in 1990. This is about 4.8 times the 1967 capacity. This rate of increase very nearly equals that shown for energy sales in Table A-b of Appendix A.

Low Voltage Switching Equipment

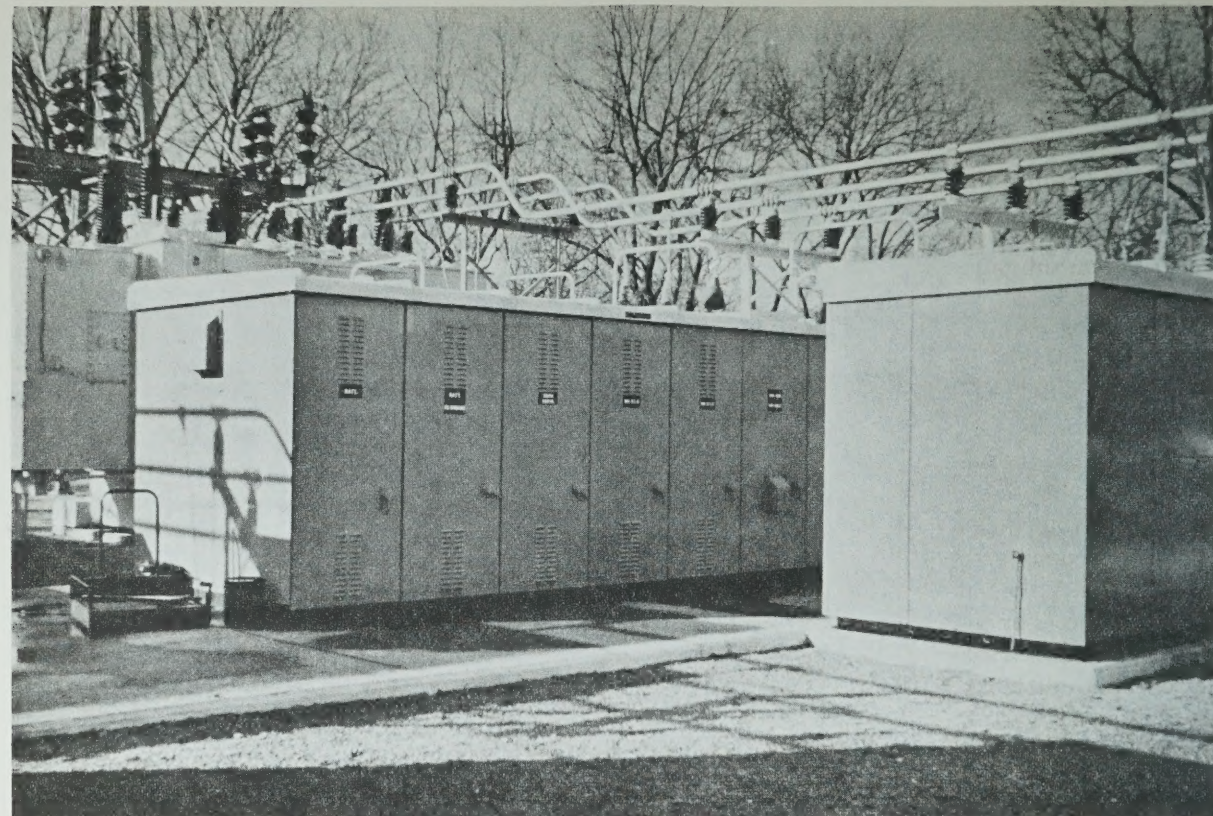
Switching equipment for distribution circuits may be either open type or metal-clad. In the open type, the switches and other associated equipment are separate units that are connected with bare conductors supported on porcelain insulators.

In contrast, metal-clad switchgear is assembled in enclosures, usually by the manufacturer. All of the required connections are made within the enclosures, so that the completed assembly can be installed as a unit at the substation site. The enclosures are equipped with doors to permit access for operation, inspection, and maintenance of the equipment within. Metal-clad switchgear is particularly applicable with distribution voltages of 15 kV and lower. For distribution voltages above 15 kV, the open type has been more generally used.

Location of Substations

Future needs for electric energy require that additional sites for substations be provided. If the average capacity of all existing substations were doubled by 1990 and all new substations installed were twice the average capacity of substations in 1967, the number of substations required by 1990 would still be about 2 ⅓ times the number of substations existing in 1967.

Ideally, a distribution substation should be



Metal-Clad Switching Equipment.

located near the center of its service area. It is becoming increasingly difficult to place substations at optimum locations because of zoning restrictions, lack of available land, or objections by the public. If the electrical needs of a community are to be met satisfactorily, the community must recognize the technical and economic factors that dictate locations of distribution substations. It is also necessary that the utilities locate and design their installations to meet reasonable environmental requirements.

The importance of substation sites and electric service is clearly evident in the planning of new cities. For example, the plans for the new city of Columbia, located about halfway between Washington, D. C. and Baltimore, Maryland, make provision for six substations to supply electric power. This city will occupy approximately 22 square miles and will provide complete living accommodations for over 100,000 people.

Distribution Substation Investment

The investment in distribution substations by Class A and Class B investor-owned electric utilities at the end of 1967 was approximately 7 percent of the investment in total electric utility plant and approximately 19 percent of the investment in the electric distribution plant. As shown in Figure II-1, the investments in distribution substations and total distribution plant have increased at approximately the same rate during the 10-year period from 1957 to 1967.

The total investment in substation plant has increased during these 10 years at a rate slightly less than that for substation transformer capacity. Thus, the investment in substation plant per kVa of transformer capacity shows a modest downward trend to the 1967 value of about \$19.60 per kVa. If this trend continues, the 1990 substation investment will be about \$16.30 per kVa of transformer capacity in service as shown in Figure II-2.

During past years, the general increases in costs of labor and materials, and the costs of more sophisticated controls and more elaborate arrangements to improve reliability, have been offset by improvements in design and by the lower per unit cost associated with larger components. However, it is doubtful that this downward trend of costs will continue to 1990. It seems likely that increasing costs for sites, extensive aesthetic treatments, and increased reliability features will

outweigh the savings associated with lower costs for larger components, and the investment per kVa will not continue to decline as indicated in Figure II-2.

Factors Influencing Substation Size

A particular load area may be served by small distribution substations closely spaced or by larger substations more widely spaced. The choice of substation size and spacing is influenced by the distribution voltage as well as by the availability of suitable sites and of routes for the transmission and distribution lines required. In high load density areas, the station capacity is often limited by the number of distribution circuits that can be physically routed from the station. Thus, as load density becomes greater, increase in capacity per circuit rather than in the number of distribution circuits is necessary if the lower unit costs associated with larger substations are to be realized. To arrive at optimum designs, the total cost of transmission, substation and distribution must be considered.

The results of a planning study of an idealized distribution system which illustrates the effect of distribution substation size and distribution voltage on cost are summarized in Table II-a. In this study, the load was assumed to be uniformly distributed, and the distribution circuits arranged to provide equal loading. It was also assumed that circuits would be rated for 65 percent of thermal capacity for normal conditions and 100 percent for emergencies.

As indicated in Table II-a, there are significant differences in cost for the different combinations shown for the idealized layout. A study of this type is useful as a guide. In actual applications, the cost ratios can be expected to differ somewhat, dependent upon conditions in a particular area. For example, extensive use of underground construction for distribution would be expected to change the relationship between 13 kV and 34.5 kV costs for a particular size of substation but not to alter appreciably the relationship of costs between one substation and another.

Factors Tending to Increase Optimum Capacity

The following factors are tending to increase the optimum capacity of substations.

Lower Cost Per Unit of Capacity.—There are a number of components in the substation whose cost does not increase in proportion to station capacity. Among these are land and site develop-

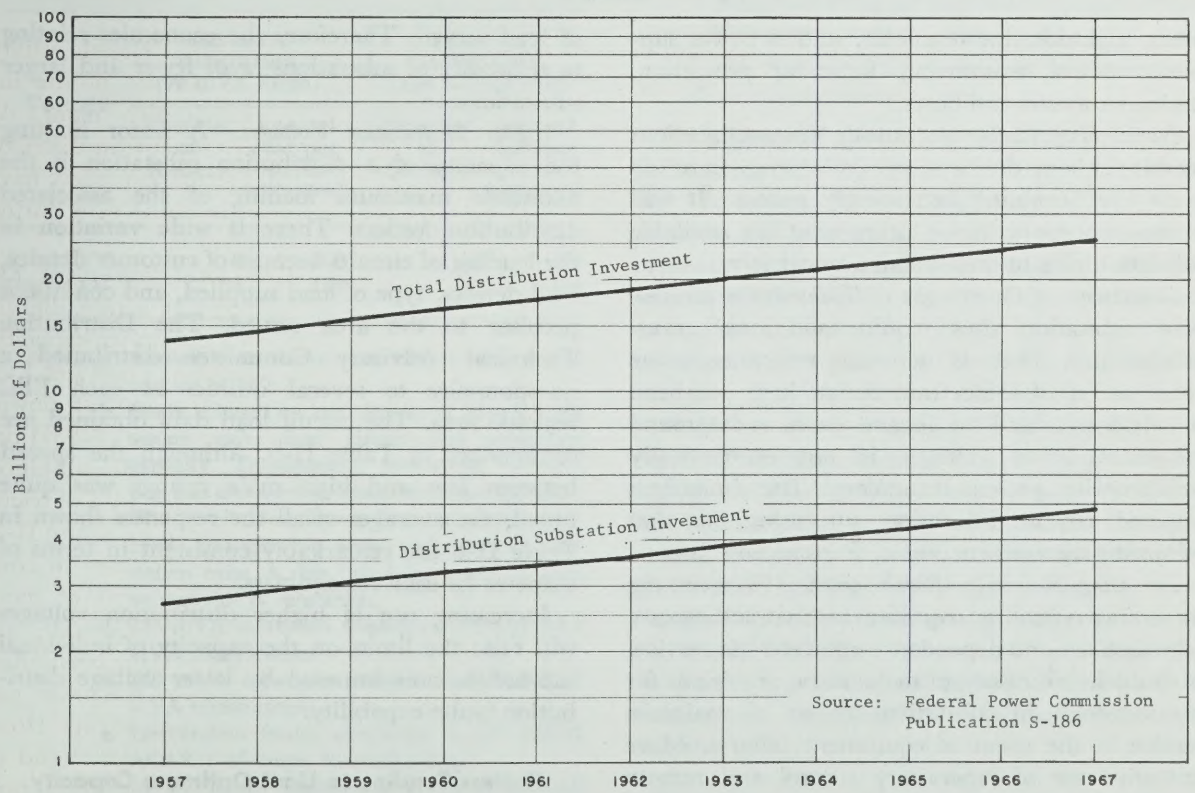


FIGURE II-1.—Relationship of Distribution Substation to Total Distribution Investment. Class A and B Investor-Owned Electric Utilities.

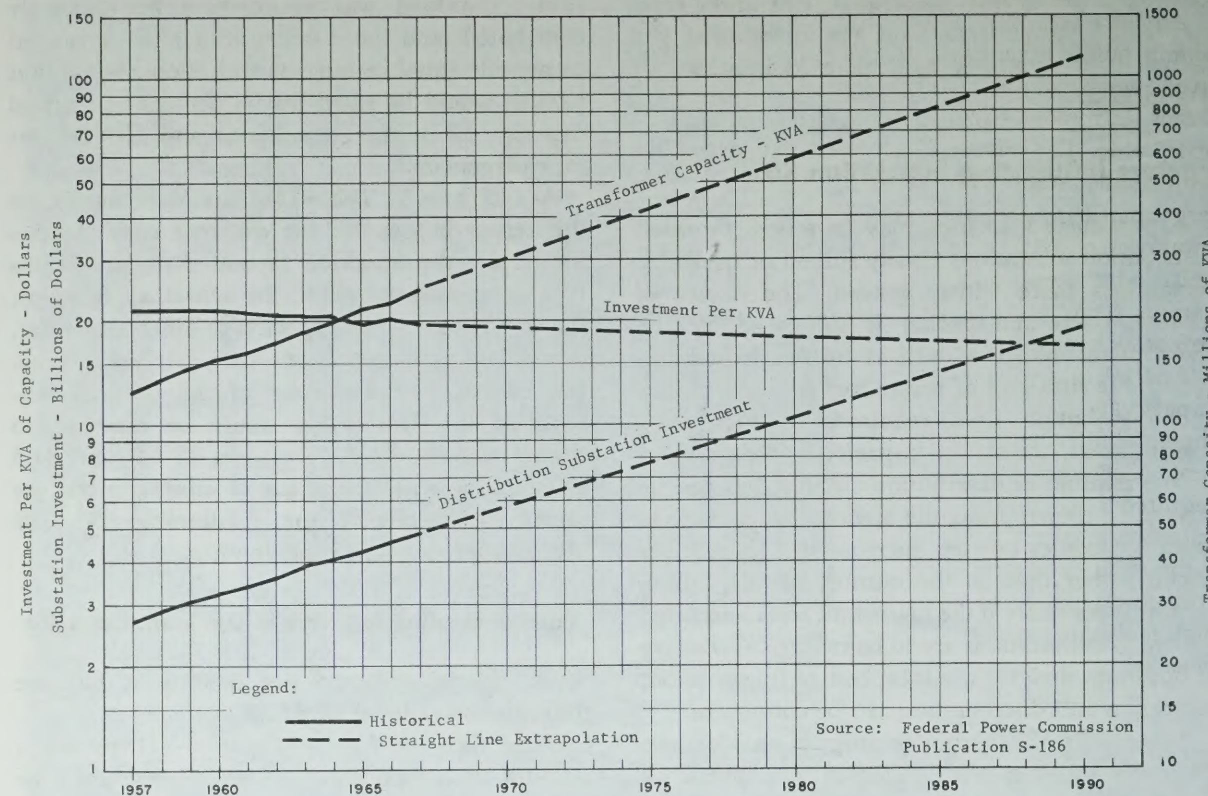


FIGURE II-2.—Distribution Substation Investment and Transformer Capacity. Class A and B Investor-Owned Electric Utilities.

ment, high-side line terminals, station power supplies, control equipment, lightning protection, station structures and buses.

Diminishing Number of Available Sites.—Objections by the public to the location of substations in urban areas are becoming increasingly serious. It will become necessary in the future to utilize available substation sites to their maximum capacity.

Limitations on Construction of Transmission Lines.—New substation sites require additional transmission lines. There is increasing resistance to the construction of these transmission lines overhead in urban areas and the general use of underground for transmission voltages is not economically feasible with present technology. The limitations imposed require substation site selections that minimize the construction of transmission lines.

Increasing Reliability Requirements.—To meet the increasing reliability requirements that accompany increased use and dependence upon electric service, it could be necessary to make more provisions for contingencies in substations so as to maintain service in the event of equipment failures. More extensive use of supervisory control and remote monitoring equipment may be indicated. The cost of these provisions is related more closely to the number of stations than to the total amount of load served. Therefore, the economics relating to reliability of substations favor fewer and larger substations.

Higher Distribution Voltages.—A factor limiting the capacity of a distribution substation is the allowable maximum loading of the associated distribution feeders. There is wide variation in the loading of circuits because of customer density, load density, type of load supplied, and conditions peculiar to the area served. The Distribution Technical Advisory Committee distributed a questionnaire to several utilities in each FPC regional area. The circuit load data obtained are summarized in Table II-b. Although the spread between low and high mVa ratings was quite broad, the averages of all the responses shown in Table II-b are remarkably consistent in terms of amperes for each voltage class.

Increasing use of higher distribution voltages will raise the limits on the capacity of individual substations now imposed by lower voltage distribution feeder capability.

Factors Tending to Limit Optimum Capacity

The following factors are tending to limit the optimum capacity of substations.

Aesthetics and Noise.—It is sometimes possible to obtain public acceptance of a station that is relatively small, simple and inconspicuous, where a larger and more elaborate station might not be acceptable. The transformer noise level associated with smaller stations is a lesser problem than with larger stations. The noise produced by the larger transformers may be reduced by obtaining special units with lower noise levels or enclosures of various types may be constructed. However, the cost of such measures can be considerable.

Fault Duty Requirements.—Increases in substation capacity generally impose higher fault duties on the equipment used to interrupt short circuit current. Consequently, higher rated equipment is required both in the substation and on the distribution feeders. Distribution substation equipment such as disconnecting switches, buses, and voltage regulators must be able to withstand the high fault current. Conductors used on the feeders must be large enough to minimize the probability of serious damage from faults on the distribution lines.

TABLE II-a

Effect of Substation Size and Distribution Voltage on Cost

Voltage	135 mVA substation (90 mVA Firm)		240 mVA substation (180 mVA Firm)	
	Number of feeders	Annual cost per mVA (relative)	Number of feeders	Annual cost per mVA (relative)
138–13 kV..	8	160	16	123
138–34 kV..	4	144	7	100

Notes: a. Annual costs shown are relative with lowest cost set at 100.

b. Study is based on load density of 20 mVA per square mile, firm circuit and substation capacity. Transmission, substation, distribution and transformer annual costs are included. The distribution layout is an idealized overhead arrangement with underground substation exits. A ring bus is provided on high voltage side of substation.

c. 135 mVA substation consists of 3–24/32/44.8 mVA transformers.

d. 240 mVA substation consists of 4–40/50/60 mVA transformers.

e. Distribution feeder conductor is 568 MCM ACAR (745-amps. thermal rating).

f. 13 kV feeder capacity is 11 mVA normal, 17 mVA emergency.

g. 34 kV feeder capacity is 29 mVA normal, 44 mVA emergency.

h. Subtransmission voltage is 138 kV.

TABLE II-b

Distribution Feeder Ratings

Voltage class	Maximum rating—mVA (average of all replies)	
	Normal	Emergency
4– 5kV...........	2.4	3.4
12–15kV...........	7.5	11.4
20–25kV...........	11.3	17.2
30–35kV...........	19.3	30.0

Measures that can be taken to limit the available short circuit current include the use of:

Nonparallel operation of substation transformers.

High impedance transformers.

Neutral reactors with wye connected transformers.

Phase reactors.

Measures to accommodate and minimize the effect of higher short circuit current include the use of:

Equipment having high interrupting ratings.

Protective relays and equipment with faster reaction time to limit the duration of short circuit current.

An economic balance must be achieved between the savings derived from the larger substations and the added costs for higher duty rated components. As substations continue to increase in capacity, the economic and operating problems associated with higher short circuit currents tend to become more severe. This problem will require considerable attention on the part of substation designers and manufacturers of equipment.

Limitations Imposed by Existing Distribution Voltages and Existing Sites.—As indicated previously, higher distribution voltages are necessary to realize the full potential of larger substations. In most instances, new distribution circuits must be integrated with existing distribution facilities to some degree. Where this involves large scale conversions of existing facilitities, economics may dictate the retention of a smaller substation. The size of an existing site may also limit expansion of the substation.

Reliability

Historically, the reliability of distribution substations has generally been high. As loads have

increased and more emphasis placed on service continuity, additional measures have been taken to reduce the frequency and duration of interruptions. Measures to improve reliability include the following:

Increased Protection for High Voltage System.—Use is made of circuit breakers on the high voltage bus to protect the station from being momentarily interrupted upon loss of an incoming line or a transformer. Where circuit breakers cannot be justified, automated disconnect switches operating in conjunction with circuit breakers on the remote terminals of the transmission lines, are used to isolate points of trouble. Automatic sectionalizing or throw-over to alternate sources are also employed. These methods are often supplemented by supervisory control systems that permit remote and immediate operation of essential switches within the station to isolate the faulted section and to restore service to the remainder of the station.

Reserve Transformer Capacity.—As substations have increased in size, the number of customers exposed to interruptions following a transformer failure has also increased. The size and weight of large transformers makes it impractical to replace a faulted unit quickly with a centrally located spare. To provide for failures, reserve transformer capacity may be installed in each station or the feeder arrangement may be such that load can be transferred to other stations. With large transformers, it is seldom possible to transfer sufficient load to other stations, and it is necessary to provide reserve capacity nearly equal to the load normally carried on the largest transformer. The emergency overload capability of the remaining transformers is considered as reserve capacity under these conditions.

For smaller transformers, mobile units may be employed as an alternate to reserve capacity in each substation. The time required to transport the mobile unit and make the necessary connections must be considered. Mobile transformers are useful as temporary installations to facilitate construction or maintenance work that requires existing facilities to be removed from service.

Increased Protection for Low Voltage Systems.—As with the high voltage section, the low voltage portion of substations receives increased attention as the substations grow in size. The feeder circuit breakers are being constantly improved so as to interrupt faults in a shorter time. Vacuum interruption devices have the promise of reducing contact maintenance problems and providing faster clearing times. Relays and reclosing sequences are being altered to achieve better logic and more dependable operation.

Substations supplied with two or more transformers are generally arranged to carry the load with one transformer out of service. The feeders which are connected to the transformer that fails may experience a short interruption prior to transfer to the remaining transformers in service.

Remote Alarm and Control Systems.—Use is made of systems that supervise the operating conditions at substations and transmit operating information, or an alarm if a switch operates, to control centers. These systems may provide for remote operation of switches and other functions essential to operation of the station. These systems have been used principally for the large bulk transmission stations. They are now being used more frequently in distribution substations and this trend is expected to accelerate in the future.

Research and Development

The increasing size of substations, the increasing emphasis on appearance, the increasing dependence on continuity of service, and the ever-present economic pressures to optimize designs and costs continue to stimulate research and development by equipment manufacturers and utilities. Much of this work is devoted to improvements of existing equipment and designs, but new concepts are also being studied.

Among the new concepts receiving attention is the use of SF_6 (sulfurhexafluoride) gas for insulation of high voltage bus and switchgear. Should compact metal enclosed switchgear become practical and economical for transmission voltages, the space required for substations could be greatly reduced. This development could permit increasing the capacity of existing stations on small sites or converting to higher transmission voltages. The appearance problems now associated with the high voltage sections of substations could be reduced by the development of smaller sized high voltage circuit breakers. Vacuum interrupting units are a possibility, and there is hope that solid state devices may be used for current interruption in the future.

Reduction of the noise generated by large transformers is a matter that requires increased attention for substations in residential areas.

Continued progress is needed in the development of protective and control schemes for dis-

tribution substations. The reliability of supervisory control systems has been improved and they are being applied on a broader base. Solid state devices have been developed for relay applications. Developments are under way to incorporate more logic in the reclosing schemes of feeder circuit breakers and reclosers. Devices to detect incipient faults in transformers are now practical. Magnetic tape data recorders and high speed solid state event recorders are being developed for substation applications.

Some progress has been made in the development of simplified loadbreak switches for both the high and low voltage sections of substations but additional work is needed. Better protection of control circuits from surges is needed. More economical means to limit short circuit currents are desirable.

Continued development of substation designs is needed to improve appearance, simplify construction and increase reliability. Development of computer programs to optimize designs and evaluate reliability of equipment and systems should be accelerated. A basic requirement is the accumulation of more extensive data relating to failure rates.

On the part of equipment manufacturers, development of new methods and procedures for quality control and pretesting of designs is needed. On the part of the utilities, new methods must be initiated to train personnel to operate and maintain the increasingly complex equipment of the future.

SECTION 2—OVERHEAD DISTRIBUTION

Overhead distribution is the last link in a chain of system components involved in the supply of electric energy to the majority of customers. Overhead distribution lines account for 18 billion dollars or about 55 percent of the investment in the distribution system. Because distribution is composed of a large number of small components, it is not generally appreciated that the investment in the overhead portion of distribution alone exceeds the investment in the total transmission system. At the end of 1967, there were over 3 million pole miles of overhead distribution lines in the United States. The evidence of this large investment is visible on almost every highway or street. From the standpoints of investment and area coverage, overhead distribution lines play a very important part in the delivery of electric power.

Historical Trends

Through the years, the extension of overhead distribution has been symbolic of growing progress and prosperity. Overhead lines have been extremely well suited to accommodate load growth. The overhead lines can be installed in a relatively short period of time in all types of terrain as necessary to satisfy current load requirements. The lines can be built in the early stages of land development to supply the temporary power needed for building construction, or they can be built after the land development has been completed, without damage to newly seeded and landscaped areas or the finished paved streets, sidewalks or driveways. When existing loads are increased, or new customers are added, the facilities can be readily increased in capacity. When the load in an area reaches the practical limit that can be supplied at the existing distribution voltage level, the circuit voltage can be raised, using the same conductors and supports.

Because of these advantages, overhead distribution is the most economical way to supply electric power, except in extremely high load density areas where overhead construction is not practical. The lower cost of overhead compared to underground is related to the fundamental requirements for the distribution of electricity. The conductors must be insulated from all surrounding conductive materials, and the heat generated in the conductors and associated equipment carrying the current must be dissipated. For overhead distribution, free air satisfies both requirements. With underground, however, conductors must be completely covered with insulating materials, and the opportunity for heat dissipation is restricted.

In the past several years, there has been rapid growth of underground distribution in new residential areas. In spite of this trend, overhead distribution predominates and continues to increase annually as shown in Figure II-3.

The data for the investor-owned utilities and

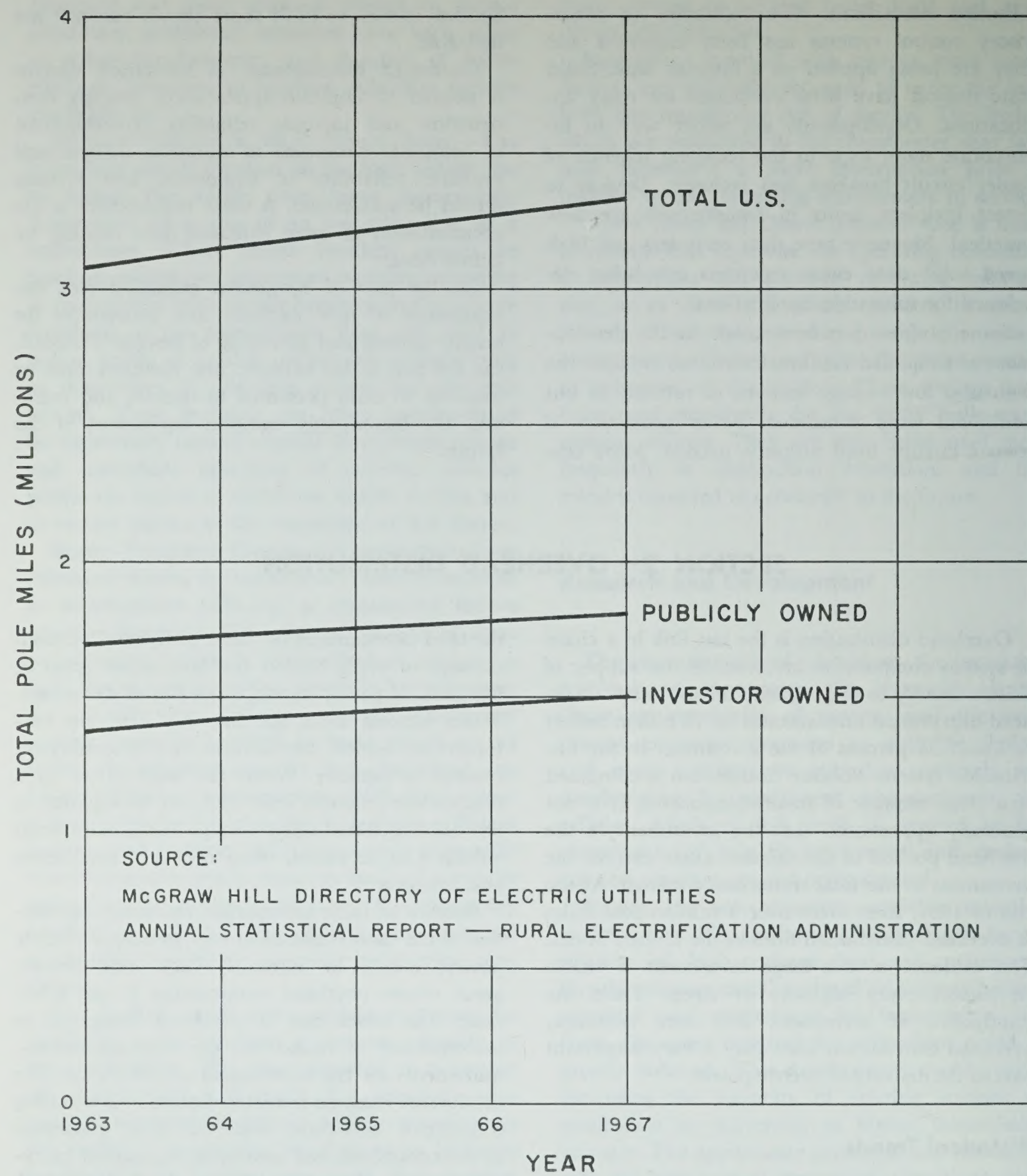


FIGURE II–3.—Pole Miles of Overhead Distribution in U.S.

the municipals were compiled from the McGraw-Hill Directories of Electric Utilities and that for the rural electric cooperatives from the Rural Electrification Administration Annual Statistical Report. The fact that, during the year 1967, more than 60,000 miles of overhead distribution were added is a measure of the tremendous scope of the program which would be required to install all new additions underground.

Overhead Distribution Lines

The overhead system is made up of radial distribution feeders that extend out from the substations to serve the surrounding areas. The portions of the feeders immediately adjacent to the substations may be installed underground to eliminate overhead congestion and to improve appearance. Usually this underground section

Crossarm Construction Open Wire Secondary.

near the substation is a small percentage of the total feeder length. Most of the feeder is overhead, supported on poles located along the highways or streets or on back property lines.

An overhead feeder usually consists of a three phase, main line section, and several single or three phase laterals that branch off the main line. The three phase section includes three isolated primary conductors. The system classified as grounded wye has the three isolated primary conductors and a ground conductor which serves as both the primary and secondary neutral. The grounded wye is the system most generally used and is preferable for underground distribution. The single phase laterals that supply most of the residential customers consist of one primary conductor and a grounded neutral.

Each primary distribution circuit supplies a large number of transformers that step the primary voltage down to the levels at which it is used by the customers. Secondary circuits then carry power at these lower voltages from the transformers to the customers in the immediate vicinity. The secondary wires are installed on the poles below the primary. Services that supply the individual customers are connected to the secondary wires.

The conductors are arranged on the pole in various configurations. Crossarms have been used extensively to support the primary wires, with the secondary wires installed on racks in vertical configuration at a lower level. More recently, armless primary construction and spacer type primary cable have been adopted, and cable type secondary has replaced open wire secondary rack construction. These changes to improve both the appearance and operating characteristics of the lines, have been made possible through the development of new materials. Fiberglass supports, in-

Spacer Cable—Cable Secondary.

sulators capable of withstanding forces of horizontal mounting, and solid dielectric insulation suitable for outdoor exposed applications are among the recent developments. These modern designs have greatly improved the appearance of overhead distribution.

Voltage and Loadability

Since the electric energy delivered is the product of the voltage and the current, increasing the distribution voltage level of a feeder increases its load carrying ability. Consequently, the trend has been to increase operating voltages rather than add more circuits whenever the load in an area exceeds the capability of the existing feeders. Voltages in the 12,000 to 15,000 volt range have been used extensively for rural electrification for many years. They have now become the most commonly used voltages in both rural and urban areas. The voltages in the 20,000 to 34,500 volt range are being used more widely for distribution feeders, and this trend can be expected to continue. Converting to a higher voltage level can often be accomplished by only changing the insulators, transformers, protective and sectionalizing devices. The fact that the poles, supporting fixtures, and conductors can often be retained is an economic advantage.

The increased load capability made available

Armless construction cable secondary.

by such upgrading is usually two to three times the existing capacity, depending on the ratio of voltage change. This change does not increase the number of wires required to serve the area, and quite often results in improved appearance obtained by the rearrangement of conductors and facilities. Table II-b in Section 1 of this part of the report shows the distribution feeder capacity for the various distribution voltage classes.

Distribution Pole Lines

Most distribution lines are built with wood poles of the pine, fir, or cedar species. The major pole suppliers harvest their poles from timber lands that are under control of trained foresters. Their selective cutting and planting programs assure a continuing supply of poles and perpetuation of the natural beauty and forest resources of the country.

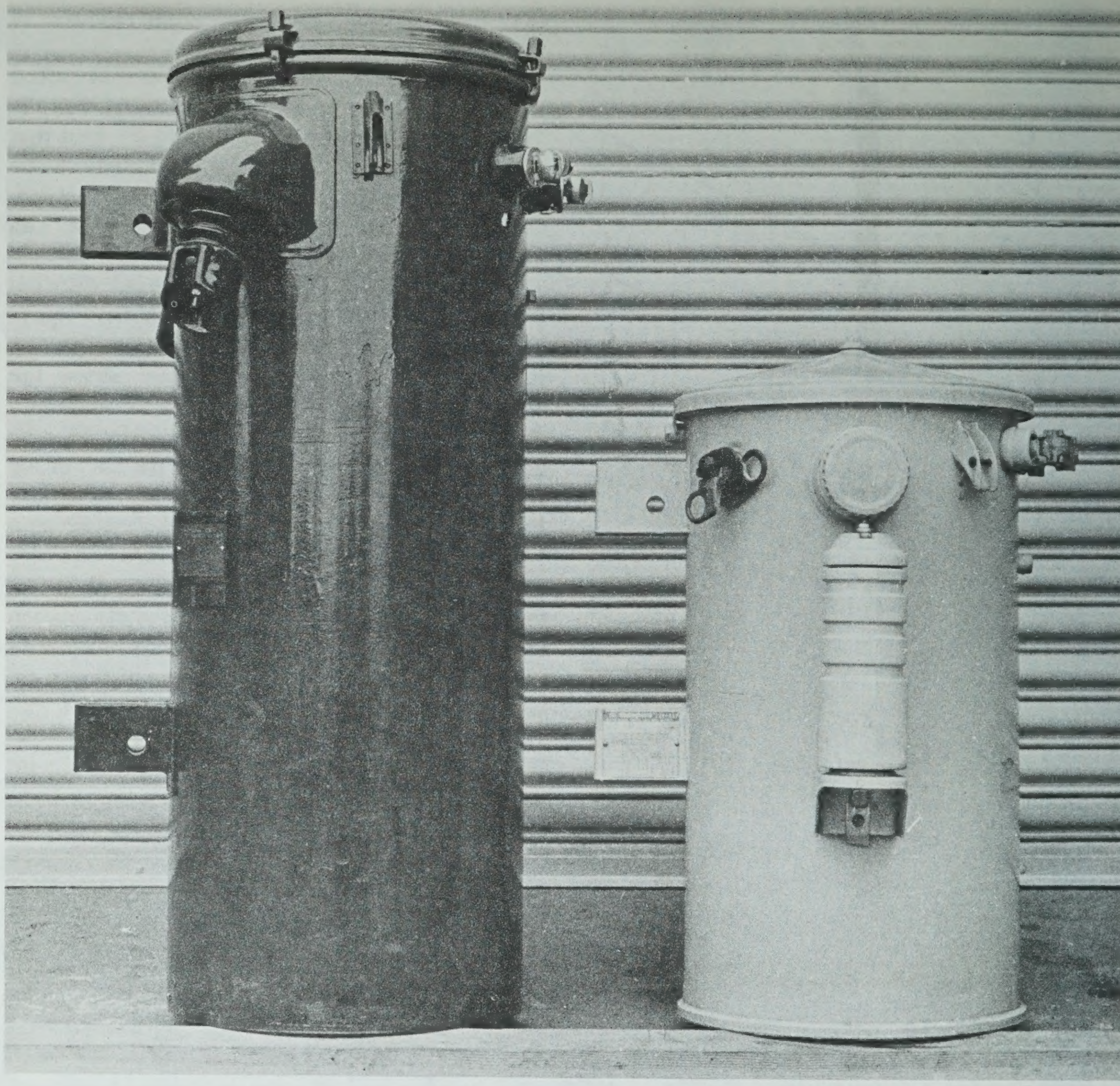
Poles are treated with preservatives that extend their physical life to 30 years or more. Supplementary treatment can be applied in the field that will extend the pole life almost indefinitely. Some preservatives darken the color of the natural wood. Other treatments retain the natural color, and some permit the color staining of the poles.

The poles that support the overhead distribution conductors and associated distribution equipment quite often also serve as the supporting structures for streetlights, telephone wires, fire alarm or municipal signal wires. Community antenna television cables have been added in some cases. This joint use of facilities on the part of the utilities is important from an aesthetic viewpoint, since it reduces the number of poles required to a minimum. Multiple use of poles has been and continues to be an important factor in the economy of overhead distribution. When the communication and electric utilities share the cost of a single support, the companies enjoy savings which are reflected in their cost of service.

To improve the appearance of overhead distribution at some increase in cost, several different pole materials and designs have been tried. Concrete and metal poles provide uniformity in appearance and reduce the guying requirements. Laminated wood poles give a modern appearance and conventional wood poles, treated and color stained, blend with the surroundings. Efforts are made to locate the poles so that the overhead line conforms with natural background. In addition to aesthetic considerations, pole line locations are influenced by many factors including minimizing the probability of vehicles hitting the poles.

Distribution Transformers

The overhead distribution transformers used to step the distribution voltage down to the customer's utilization voltage level represent about 25 percent of the overhead investment. A large number of transformers is required because each transformer, regardless of its capacity, can supply only those customers within a short distance from its location. The size of the transformer and the length of the secondary circuit between the transformer and customer are determined by the load requirements of the customer or groups of customers served. The present 120/240 volt secondary system limits the secondary length and hence the



Size Reduction of 25 kva Transformer.

size of the transformer. Possibilities for use of higher secondary voltages are discussed elsewhere in this report.

Transformers supplying residential customers and small isolated commercial loads are primarily single phase units, ranging in size from 5 to 167 kVA. Overhead transformers can be loaded in excess of their nameplate rating with usual distribution load cycles due to their ability to dissipate heat into the surrounding air. USA standard loading guides for distribution transformers, in existence since 1942, are updated periodically to reflect improvements of materials and designs.

The loading of transformers can be monitored statistically by load management programs in which the customers' energy use, obtained from meter readings, is related to demand. The energy use of all the customers connected to a particular transformer is combined to determine the total diversified demand. This is a continuing program with load checks made at frequent intervals.

Another method of load monitoring is to equip the transformers with indicating lights that will come on when the transformer demand reaches a predetermined value. This provides a visual indication so that heavily loaded units can be changed out or new units added on a planned basis, at the convenience of both the utility and the customer.

Continued improvements in materials has re-

Modern highway lighting underground area.

sulted in present day transformers which are smaller in size than older units of equivalent capacity. A standard light gray color has been adopted so that the units will blend with the sky background. These are among the developments which contribute to a better appearing overhead distribution line.

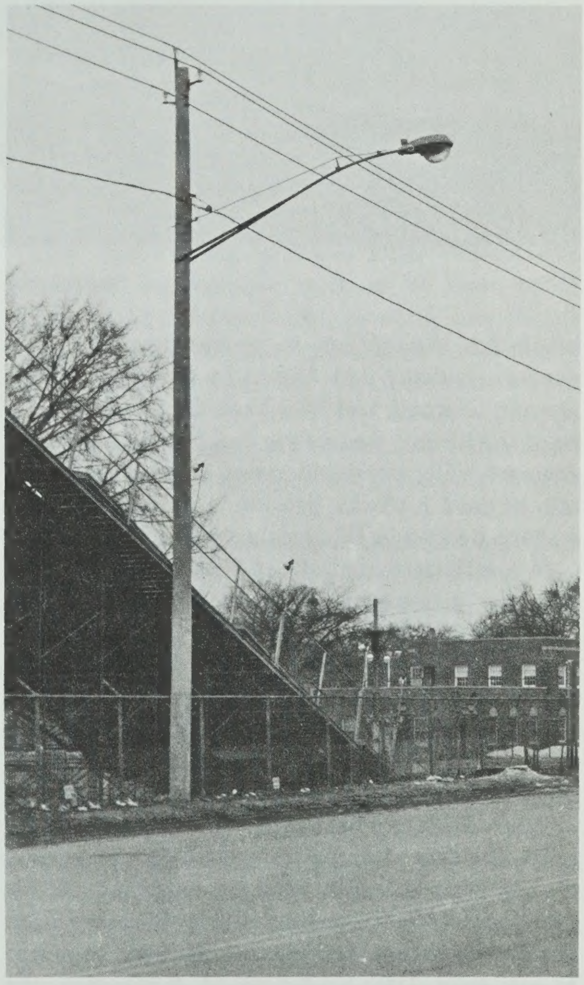
Secondaries and Services

The secondary conductors carrying the low voltage supply from the transformer are usually installed on poles in a vertical configuration, located below the primary conductors. Recently, there has been a tendency to use a three or four wire cable instead of the single wires. The size of the secondary wire is dictated by the anticipated load and the distance from the transformer to the last customer. The size and length of the conductor and its load are the factors to be considered in the design so that the voltage drop between the transformer and the most distant customer stays within acceptable limits.

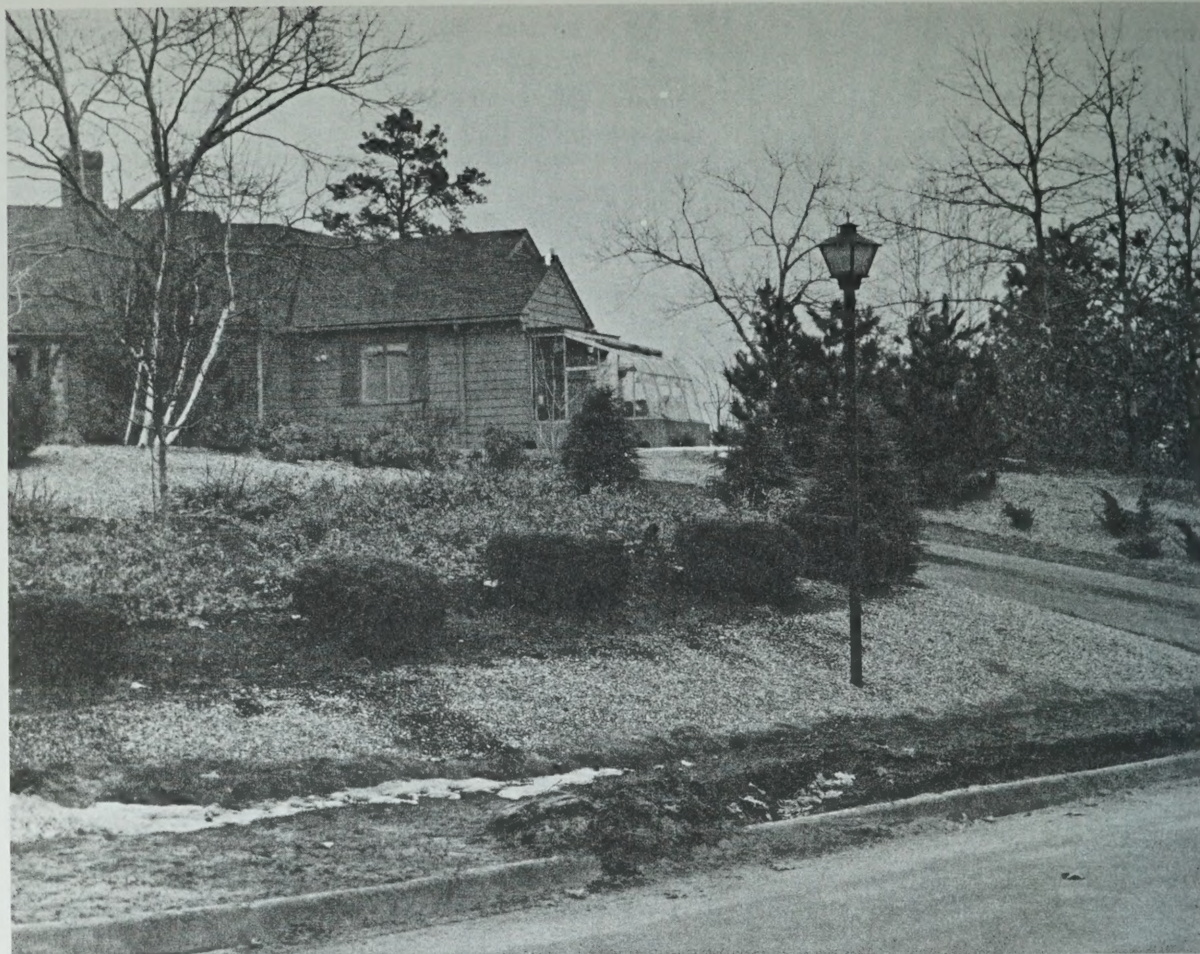
The service conductors that supply each customer are connected to the secondary conductors, usually at or near poles along the route. Sizes of services, like the secondary conductors, are determined by the customer loads and the voltage drops they produce. In older installations, separate conductors were used, but as with the secondaries on the street, there has been a strong trend toward the use of a composite cable arrangement for single phase and three phase services. These installations offer improved appearance because of the single cable effect, a neater attachment to the house and pole, and a minimum of tree clearance required. Where conditions make it difficult to obtain proper ground or building clearance, or where appearance is a special consideration, the service conductors can be installed underground. The cost of underground services is considerably higher than for overhead.

Street Lighting

The growth in population and vehicular traffic increases the importance of good street lighting,



Modern highway lighting overhead area.



Street Lighting in URD Area.

which has been shown to be instrumental in reducing accidents and crime. In the larger cities, Detroit, Chicago, and New York City, for example, records indicate that crime has shown a marked decrease with improved street lighting. Installation of good highway lighting is accompanied by a sharp decline in the number of traffic accidents.

It is estimated that about 4 percent of the distribution investment of Class A and B investor-owned utilities is in street lighting. This is only a portion of the total investment in street lighting throughout the country. Many street lighting systems are owned and financed by the communities served, rather than by the utility that may supply the energy for operation.

When the street lighting is installed on multi-use poles, the street lighting investment is only a fraction of what it would be if the support were required solely for the street lights. With overhead distribution, street lighting fixtures may be added at any time. With underground distribution, the street lighting system must be planned and the street light wires installed initially. Addition at a later date is inconvenient and expensive.

Standards for street lighting are included in the Illuminating Engineering Society Lighting Handbook. The spacing, mounting height, light patterns, and intensity of lighting recommended for the various traffic patterns and volumes are specified. A large selection of light sources is available, consisting of variously sized incandescent, fluorescent, sodium vapor, and mercury vapor lamps. The light sources are enclosed in luminaires designed to protect the lamps and to provide control of the light pattern.

Vapor type light sources are much more efficient and have six times the life of incandescent types. Improved washing techniques combined with special street light maintenance vehicles afford a fast and economical method of satisfying proper maintenance requirements. By combining street light group replacements with cleaning and maintenance schedules, costs may be reduced appreciably.

Storm Proofing

The term "Storm Proofing" is generally applied to programs for rebuilding and strengthening existing lines to bring them up to present standards and to improve their reliability during major storms. While it is not feasible to build lines strong enough to withstand the occasional severe hurricane, tornado, lightning or ice storm, it is possible to provide a high degree of protection against most of the storms to which the line is likely to be exposed. The general approach taken by the utilities to achieve improved performance is to adopt minimum strength requirements for overhead conductors to reduce mechanical failures, and to use a number of methods to insure that tree contacts and phase to phase conductor contacts do not result in permanent faults. The use of stronger conductors covered with insulation requires stronger poles and heavier guying. Protection from electrical faults can be achieved in many ways.

Increased separation between bare conductors, increased conductor tension, or a combination of both can virtually eliminate the possibility of phase to phase conductor contact. This approach is satisfactory where tree contact is not a problem.

The use of conductors covered with insulation that is capable of withstanding phase to phase contacts and contact with tree limbs, enables service to be maintained during major storms until such a time as utility crews can clear the trouble. Spacer type cable has been used for this purpose. With this construction, primary wires covered with insulation are suspended from a high strength messenger. The messenger wire is firmly fastened to the poles and the conductors are supported by spacers which are fastened to the messenger at intervals of about 35 feet. This type of construction, because of its tight configuration and the high strength messenger, has been very effective in areas where tree contact is a problem.

More recently, armless type construction using high strength conductors insulated to withstand tree contact or phase to phase contact has gained acceptance. With this design the messenger and intermediate spacers are eliminated.

The protection of overhead distribution lines from failure due to lightning is usually accomplished by one of two methods. One or more bare conductors are installed on top of the poles above the primary conductors and connected to ground at regular intervals. The overhead grounded conductor intercepts the lightning charge and diverts it to ground without damaging the line. The other method is to connect a lightning arrester or a similar discharge device between each overhead line conductor and the ground at regular intervals. The arrester provides a path by which the lightning charge can be transmitted from the overhead line conductors to ground before it has damaged the line conductors, insulators or equipment. Increased conductor separation or using conductors covered with insulation are not effective methods of lightning protection.

In order to develop the most effective program for an area, it is essential to analyze all interruption reports to determine the causes of interruptions, the trouble location patterns, and the reasons for delays in the restoration of service. The results of such a thorough analysis often indicate that major improvement in line performance can be obtained by making changes in only a small portion of the system. Usually, a combination of different types of corrections based on past performance is most economical and effective, and can be instituted in the shortest period of time.

Operation and Maintenance Techniques

Live line working practices allow routine and preventive maintenance work to be done while the circuit is energized, thus avoiding any inconvenience to the customer served. The use of highly mechanized equipment for overhead construction and maintenance, such as line trucks equipped with hydraulic diggers and booms, aerial lift trucks, and power operated tools has reduced overhead costs.

A visual inspection of line conditions and protective equipment, possible with overhead distribution, provides a simple, economical way of detecting any abnormal conditions that can be corrected before they cause circuit interruptions. In the case of circuit failure, visual inspection permits the fast location of the trouble and thus promotes the rapid restoration of service.

A relatively new thermal inspection device has been developed which provides the utility with a method for detecting overheated connections or other parts that are not discernible by normal visual inspection. This instrument measures infrared radiation emanating from any object under observation. It can be hand carried, truck mounted

or installed in a helicopter. An operator can detect hot spots simply by scanning the equipment in question. The infra-red measuring technique is useful in all areas where temperature is an important indication of impending trouble.

When overhead distribution lines are located in close proximity to trees, extensive tree trimming programs must be carried out in order to insure a reasonable degree of service reliability. This is a major cost item for the utility and frequently provokes serious criticism from the general public. To eliminate these problems as much as possible, the electric and communication utilities have cooperated with communities in the development of master tree plans and guides for tree planting that permit both overhead distribution and trees to co-exist.

Future Outlook for Overhead

It must be concluded that overhead distribution systems will be in operation through 1990 and beyond. Continuing research and development efforts should produce equipment and techniques that will improve the performance of overhead distribution. Automated and supervisory controls that will result in increased reliability of service are readily adaptable to overhead through space communication channels.

As the overhead distribution is altered to cope with the increasing loads, the general appearance will be improved. The cooperation between utilities, regulatory bodies, and the general public in the selection of line locations should provide maximum benefits to all.

SECTION 3—UNDERGROUND DISTRIBUTION

Underground distribution is not a new development. The first underground distribution lines were installed before the turn of the century and most of the larger cities in the country have had some underground distribution for many years.

Conventional Underground Distribution

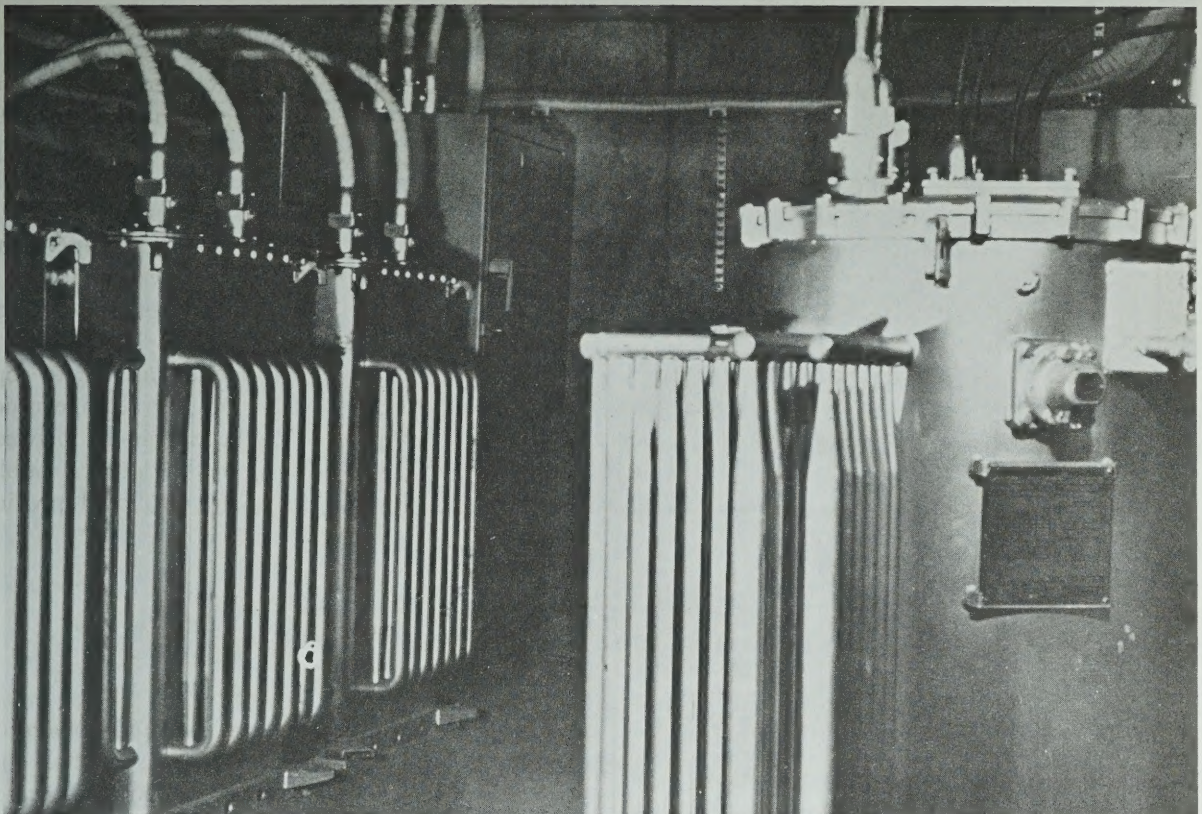
Until recently most of the underground lines were located in the central business areas of cities. In such areas, electric load densities are high, service reliability requirements are also high, vehicular and pedestrian traffic density is heavy, and overhead line clearances from buildings are sometimes unobtainable. The underground distribution systems that were originally designed to meet these conditions were quite costly compared to overhead systems.

These systems were completely underground, and all of their components had to be capable of operating when totally submerged in water, either occasionally or, in some locations, continuously. In order to protect the insulation from moisture, the cables were sheathed with lead. Transformers and switching devices were enclosed in watertight metal cases thick enough to withstand corrosion and were installed in underground vaults or manholes large enough for men to enter and to work on the equipment. Where the cables were connected to the equipment, the lead sheaths were bonded or "wiped" to the equipment terminals to provide water-tight connections. This operation requires highly skilled labor.

The cables were pulled into concrete-encased duct runs. In a high load density area such a duct run might consist of six or more ducts to accommodate several parallel primary and secondary circuits.

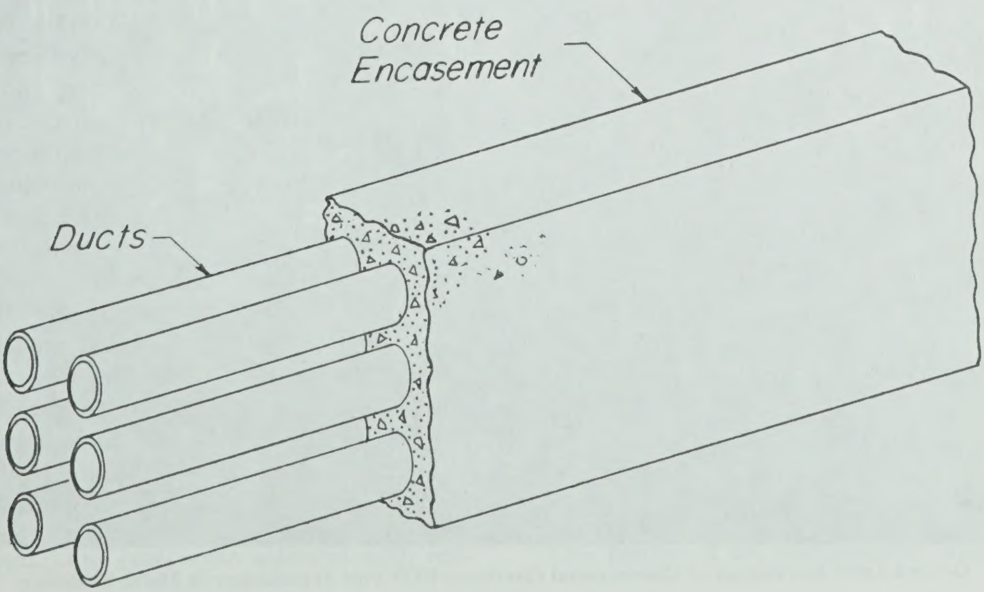
It inherently requires more time to locate and repair failures in an underground system than it does in an overhead system. In order to provide adequate service continuity with underground systems, this disadvantage must be compensated for by proper provisions in system design. The simplest such provision is a primary open loop system such as shown in Figure II-4. If a primary cable failure occurs in such a system, the section of cable in which the failure occurs can be isolated by opening the switches at each end of it. Power is then restored to all of the transformers on the loop by feeding up to the open switches from both directions. This arrangement permits service to be restored without waiting until the cable is repaired.

The open loop system has the disadvantage that service cannot be restored until the faulted section of cable has been identified and isolated by manual switching. In areas such as the business centers of large cities, this delay in restoring service cannot be tolerated, and more costly arrangements such as automatic primary transfer schemes and secondary networks are used. These arrangements are described in detail in Part I, Section 4.


Interior of Transformer Vault Showing Lead Covered Cables ''Wiped'' to Equipment Terminals.

The underground systems in operation in downtown areas today generally conform to the foregoing description. Open loops are commonly used in the smaller cities and automatic transfer schemes or secondary networks in the larger cities. One significant change is that moisture-resistant rubber insulation without lead sheathing is now generally used for the secondary cables. Oil-impregnated paper insulation and lead sheathing are still used for the primary cables. The use of polyethylene

CONCRETE-ENCASED 6-WAY DUCT RUN



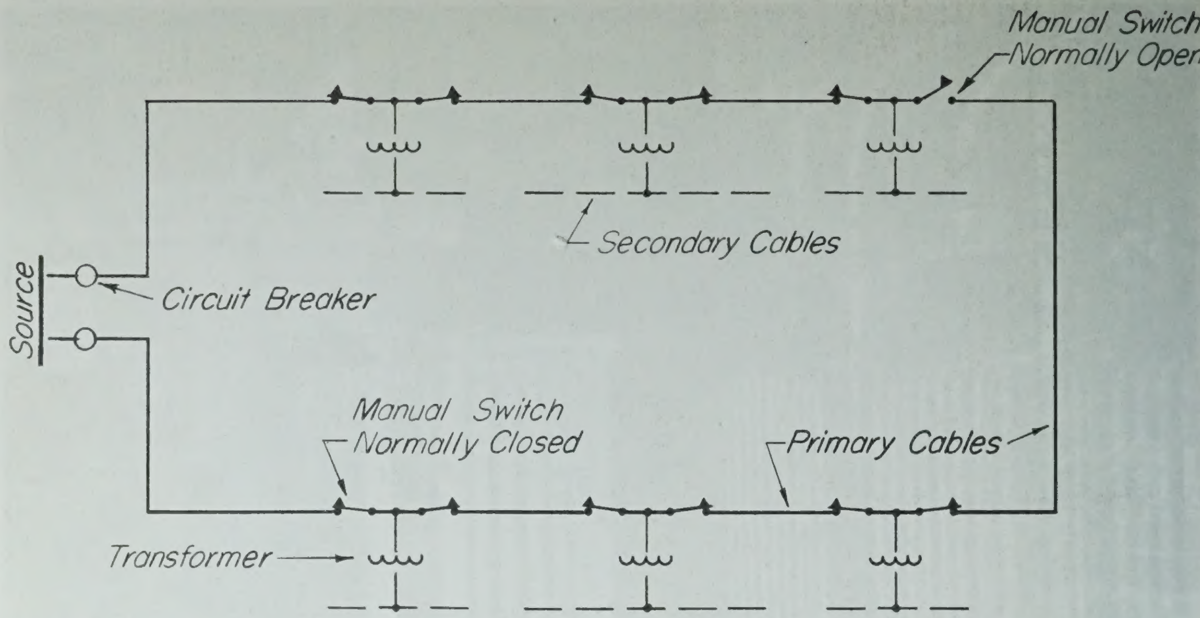


FIGURE II–4.—Primary Open Loop System.

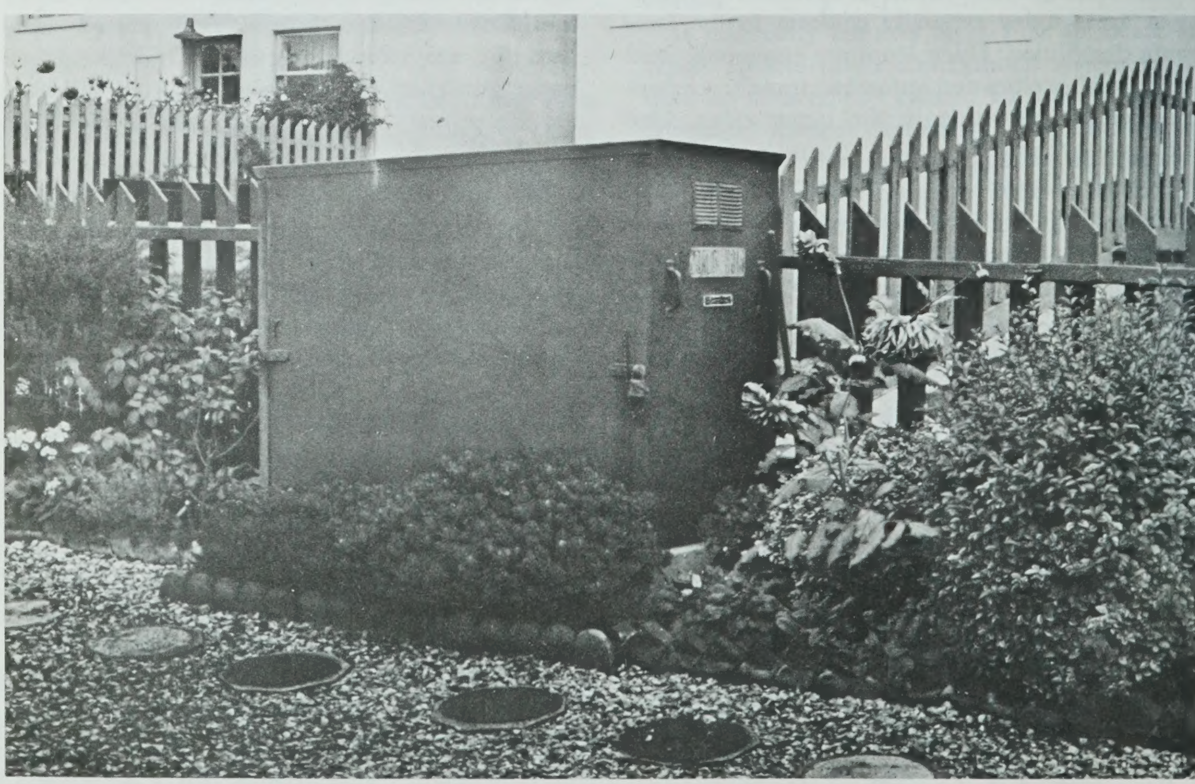
insulated cables without metallic sheath is increasing.

Residential Underground Distribution

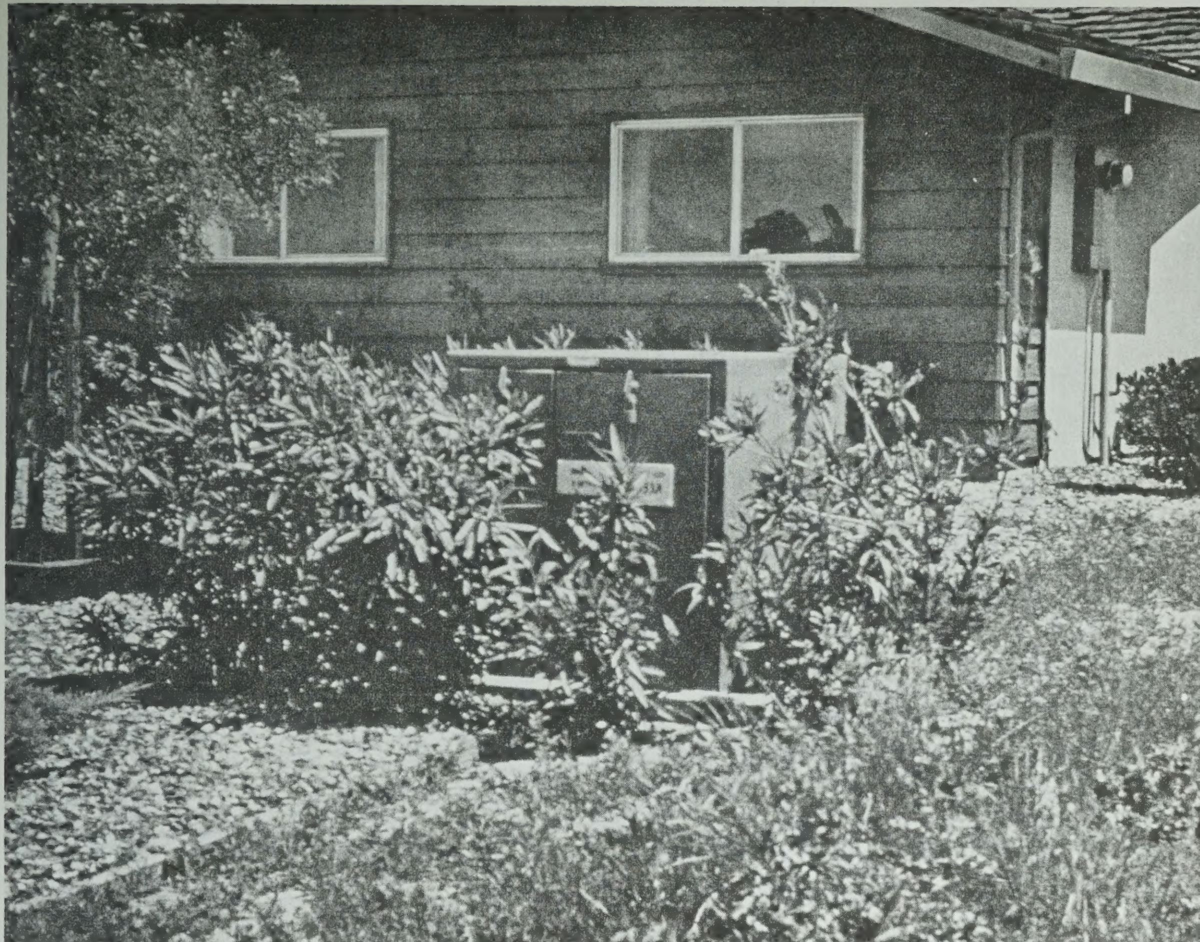
The conventional type of system designed for downtown business areas is not economically feasible for the much lower load densities in residential areas. Less costly systems were developed for these areas and a number of small scale installations were made by various utilities prior to about 1950.

Early Systems

Rubber cable insulation that was moisture resistant had been developed for both primary



Ground Level Installation of Conventional Overhead 4000-Volt Transformer in Metal Enclosure.



Pad-Mounted Transformer—12,000 Volt.

and secondary voltages. Both paper insulated and rubber insulated cables without metallic sheath were used in early installations. Instead of using concrete-encased duct lines, the cables were either pulled into nonmetallic ducts that were buried directly in the ground without concrete, or the cables themselves were directly buried. In order to avoid the use of costly manholes and submersible equipment, overhead type transformers were installed in enclosures on ground level concrete pads.

The primary and secondary cables were terminated and connected to the transformers in the enclosures above the ground level where they were not subject to submersion. A primary open loop system, such as is shown diagrammatically in Figure II-4, was normally used. Overhead type primary disconnect switches were used to sectionalize the loop and isolate faulted cables, and an overhead type primary fuse was used between the primary loop and the transformer.

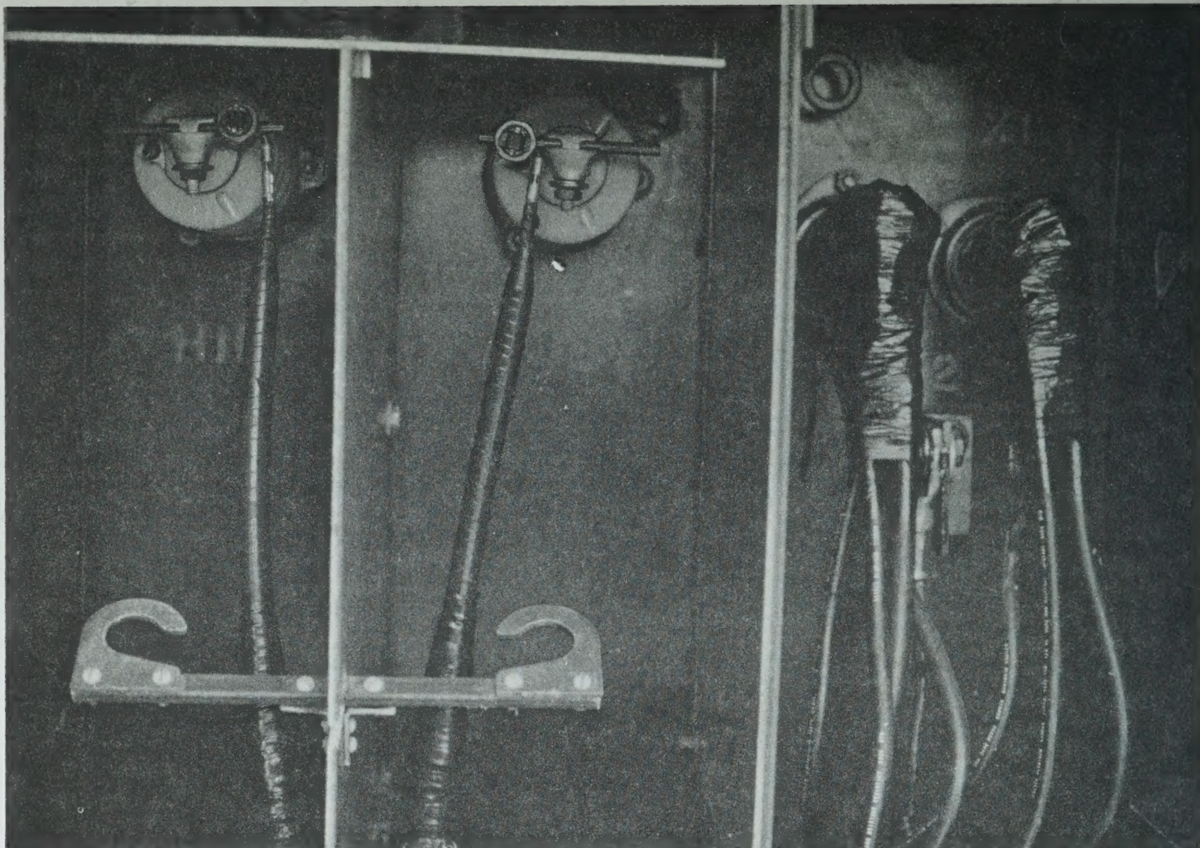
Reasonably low costs were achieved with residential underground systems of this type supplied from 4,000 volt primary circuits. However, after World War II, it became necessary to use higher voltage, higher capacity, primary circuits in order to supply the rapid suburban load growth without an excessive number of new primary circuits, substations, and transmission lines. Utilities generally adopted voltages in the 12000–15000 volt range for this purpose.

In the late 1950's a broader public demand for residential underground began to appear, creating a need for new technological advances to make lower cost underground distribution at the higher primary voltages feasible.

Advances in Lowering URD Costs

A breakthrough in lowering the cost of higher primary voltage underground residential distribution was achieved with the development of the pad-mounted transformer in 1958–59.

One feature of the pad-mounted transformer is



Interior of Cable Termination Cabinet of Pad-Mounted Transformer.

a cable termination cabinet that is either an integral part of the transformer or is bolted to one side of it. The primary and secondary terminals of the transformer extend into the cabinet and the primary and secondary cables are brought into it through the bottom. The cable insulation is terminated in the cabinet above ground level and the conductors connected to the transformer terminals.

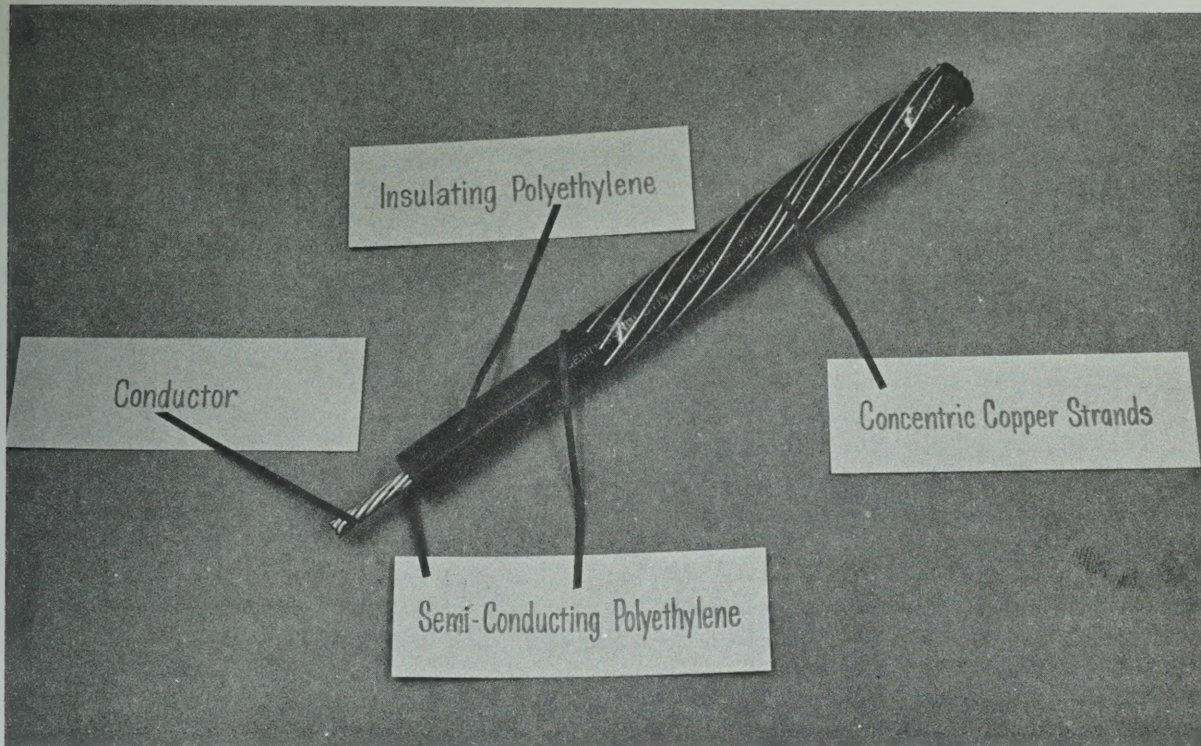
The transformer is installed on a ground level concrete pad. Such devices as primary fuses, a secondary circuit breaker and primary sectionalizing switches can be installed either inside the transformer tank or in the termination cabinet. Primary loop sectionalizing can be accomplished either by operating switches if provided, or by changing the primary connections in the cabinet, using live line tools.

Another breakthrough was achieved with the development of polyethylene-insulated primary cable for URD systems. Polyethylene is one of the most moisture-resistant nonmetallic materials known. It also has very fine electrical insulating characteristics. The installed costs for polyethylene-insulated primary cables are less than for either rubber-insulated or paper-insulated lead-sheathed cables for 12,000 volt operation.

The type of primary cable now generally in use for underground residential distribution has a number of spiral concentric tinned copper strands over the polyethylene insulation. These strands serve as a grounded shield, a return path for fault currents and as a grounded neutral conductor of the primary circuit.

The least costly method of installing cables is to bury them directly in the ground, a practice that has been used for many years and more recently has been adopted by many utilities as standard for residential underground systems. It has certain disadvantages over the conventional duct system, including the lack of mechanical protection for the cables, the problems of precisely locating cable failures in order to dig down to them and make repairs, and the high cost of replacing cables for additional cable capacity if it should become necessary because of load growth not anticipated.

Some utilities, while recognizing the necessity for a lower cost method of installing cables than the rigid duct system, were reluctant to adopt the



Concentric-Neutral, Polyethylene-Insulated, 15,000 Volt Cable.

direct burial technique. A third technique was developed about 1963. Cables were preassembled at the factory in flexible polyethylene pipes or ducts, that could be coiled on reels and laid in the trenches in the same manner as directly buried cable. This technique retains some of the advantages of the rigid duct system, while realizing part of the potential cost savings of direct burial.

Other technological advances have also contributed to lowering the cost of residential underground in recent years. They include the substitution of aluminium cable for copper, the increased use of joint trenches shared with other utilities, improved trenching equipment and techniques, and better coordination of the planning and construction work among the utilities involved and between utilities and subdivision developers. Research and development efforts directed toward further cost reduction should continue.

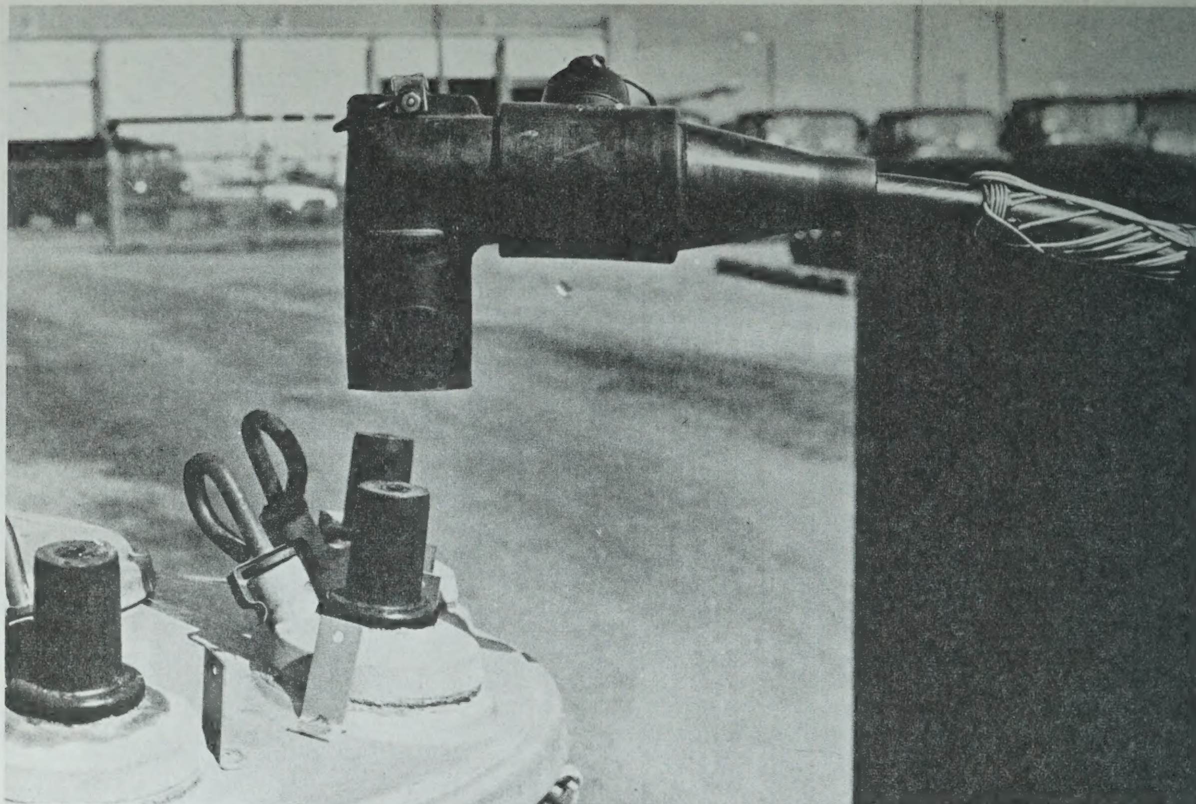
Total Underground Residential Distribution

As indicated previously, the development of the pad-mounted transformer was a major breakthrough in reducing the cost of residential underground distribution. However, it is sometimes considered as a compromise with aesthetics since the transformers are above ground and visible. Current developments have made it possible to put the transformers underground in residential systems at a moderate increase in cost over the pad-mounted type of installation.

The key development that is making total underground installation feasible is the separable insulated primary connector. With these connectors, the primary cables can be plugged into the transformer terminals, forming a water-tight connection with no exposed live parts.

By using separable connectors, and locating all terminals, operating handles, etc. in the cover of the transformer where they are accessible from the ground surface, the transformer can be installed in a small, inexpensive, form-fitting enclosure, since there is no need for men to enter it while the transformer is in place. Such an enclosure may be a section of large diameter fiber or steel pipe or composed of several short sections of large diameter concrete pipe. This type of transformer installation is commonly described as a "subsurface" installation.

There are a number of problems associated with subsurface transformer installations that are receiving further study. These include corrosion and cooling of transformers and operation of the separable connectors as switching devices. Costs



Separable Insulated Primary Connector.

of subsurface installations are moderately higher than for pad-mounted equipment.

Other Underground Distribution Lines

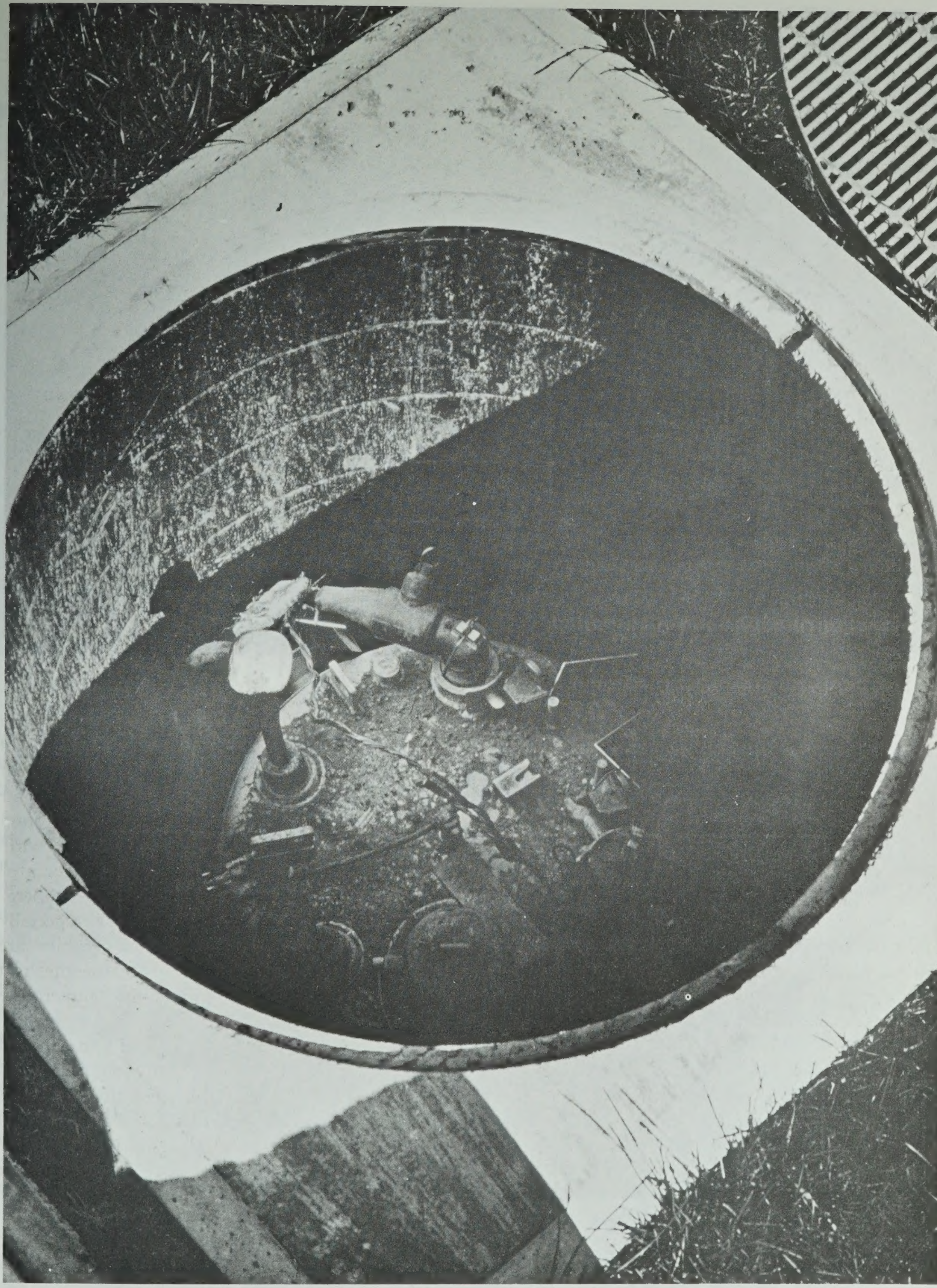
The underground residential distribution systems described previously are generally characterized by the use of small cables, small transformers, and light duty switching equipment. The primary circuits consist of only one or two cables of the type illustrated by the photograph showing a section of Concentric-Neutral, Polyethylene-Insulated, 15,000 volt cable.

The desire for underground is not limited to residential distribution however. It extends to distribution systems in medium load density developments such as shopping centers, industrial parks, and apartment complexes; and to the main primary feeders that carry power from the distribution substations to and through the local load areas. These types of lines involve higher capacity and more expensive components than residential systems, and for such lines underground construction is still much more costly than overhead.

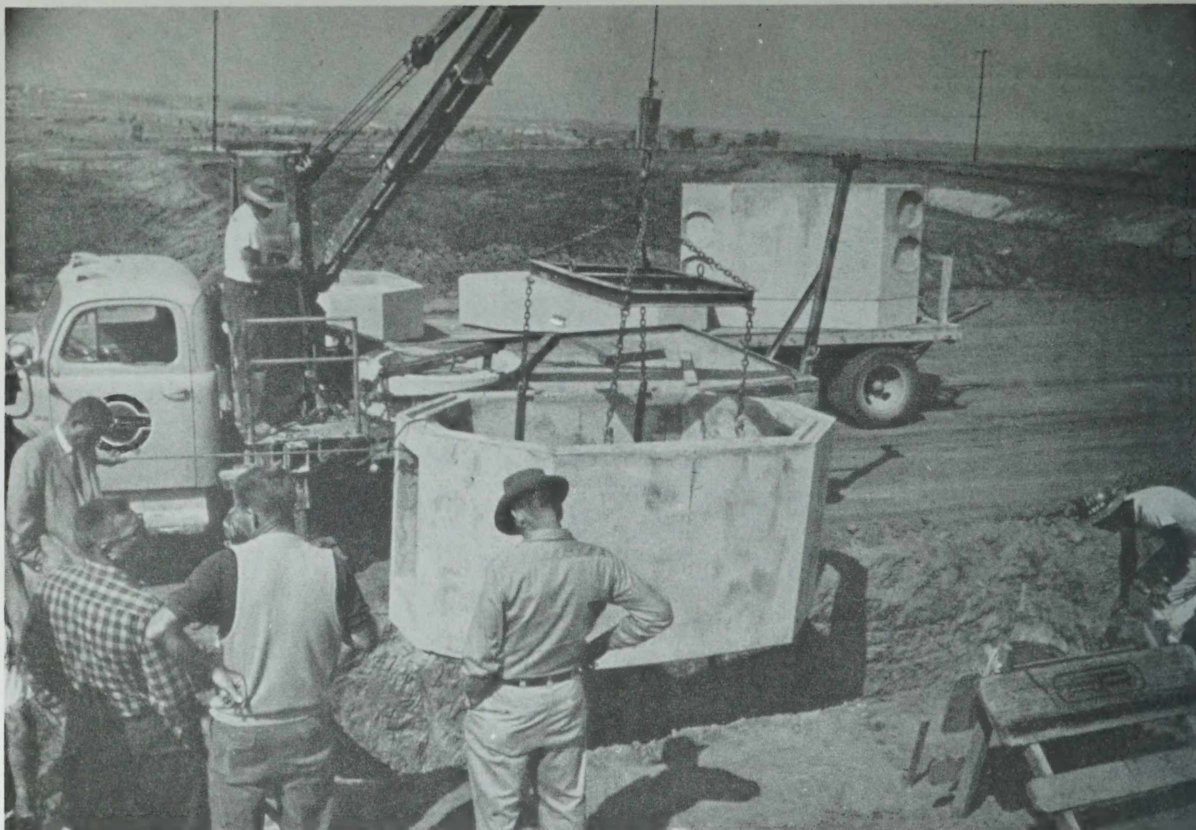
A basic reason for the high cost of placing high capacity lines underground is the problem of dissipating the heat created when electric current flows in a wire. Overhead wires are cooled by air circulation around them. Since underground wires do not have this advantage, larger wires must be used to reduce the amount of heat created and thus avoid the build-up of damaging temperatures. This problem of heat dissipation is especially serious where several high capacity cables are installed in the same duct line, because the heat produced by each cable affects the temperature of the others.

The difference between the cost of underground cables and equivalent overhead conductors increases rapidly as the capacity of the circuits is increased. For typical residential secondary and primary circuits this difference is less than 25¢ per foot of circuit. For the large cables used for three-phase main primary feeders it can be more than $3.00 per foot of circuit.

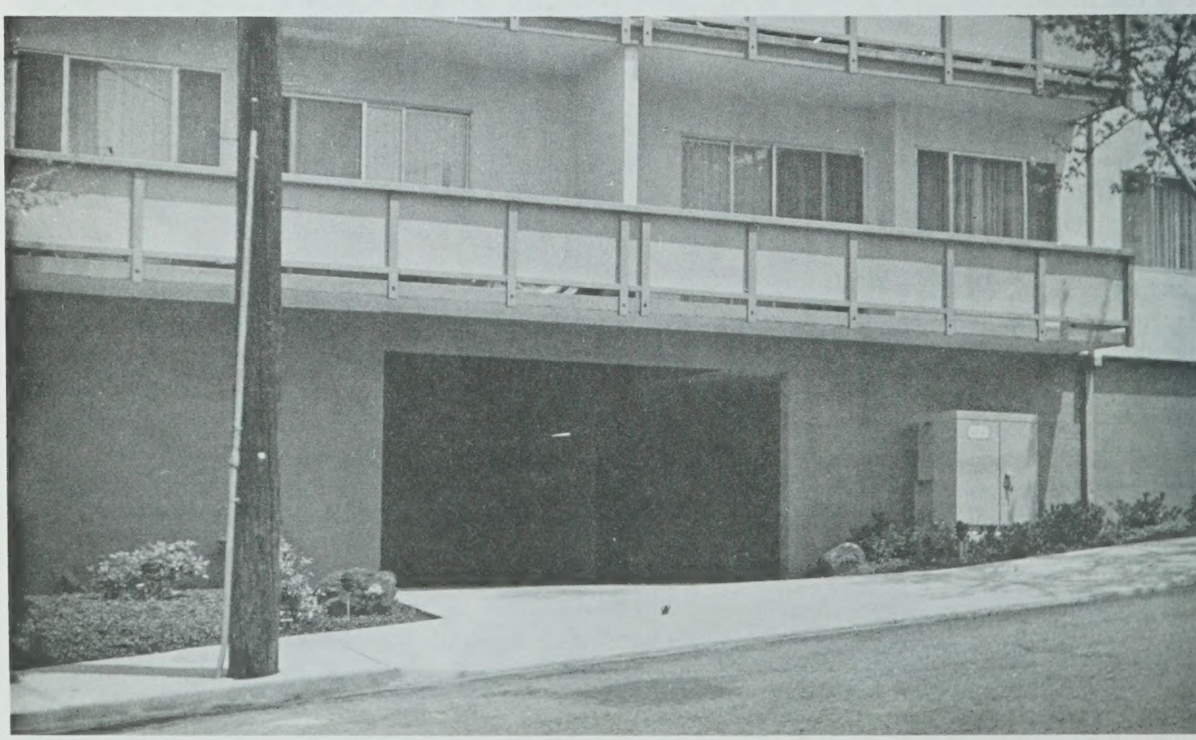
There is increasing use of cross-linked polyethylene for cable insulation. This type of insulation has better thermal characteristics than the plastic polyethylene and is preferable for larger and more heavily loaded cables. The installed



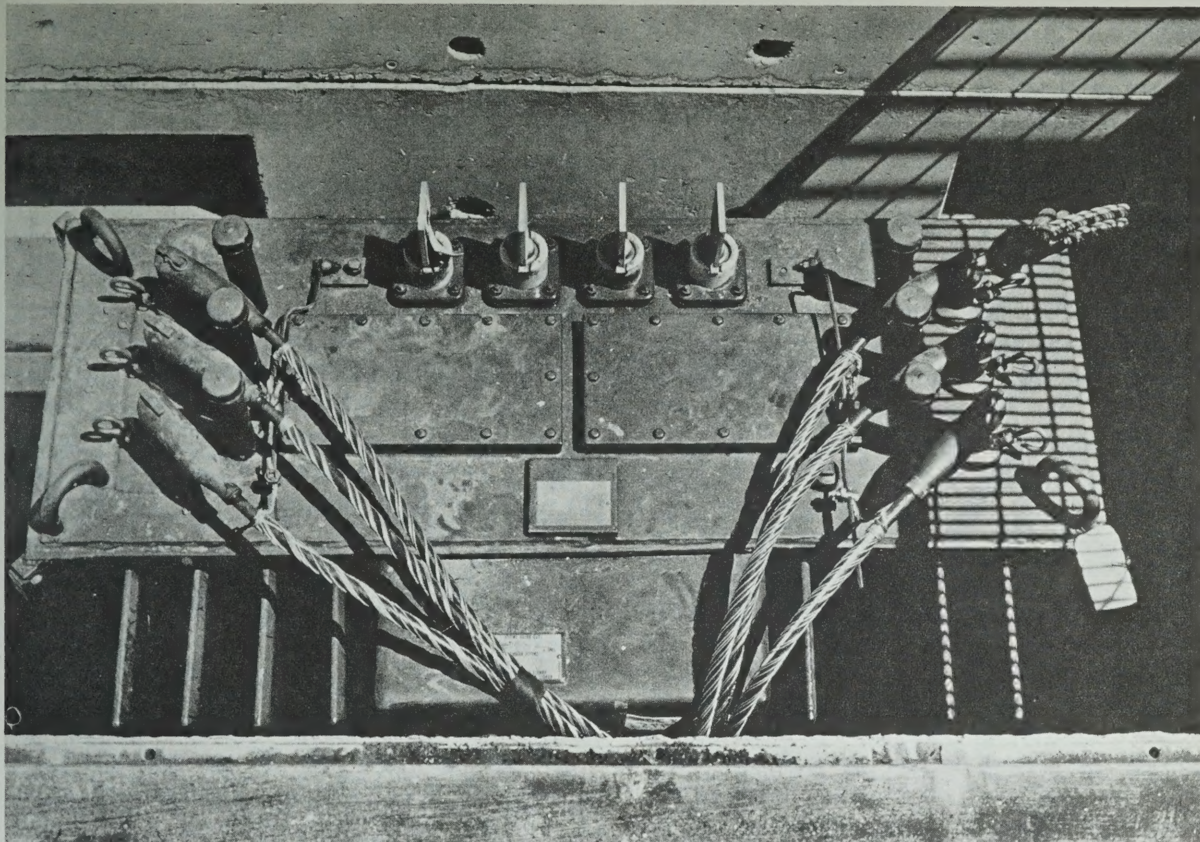
Subsurface Transformer Installation.



Precast Manhole Sections.



Pad-Mounted Transformer Supplying Apartment Building.



Subsurface Installation of Large Transformer.

cost is less than that of the paper-insulated lead-sheathed cable traditionally used for primary circuits in central business areas.

Where ducts are used, there is a trend to light weight plastic ducts that are made in long lengths and are less costly to install than the heavier conventional materials such as impregnated fiber and asbestos cement. In locations where the added mechanical protection is not essential, costs can be further reduced by omitting the concrete encasement or covering of the ducts. Use is also being made of the direct burial method for installing larger primary cables. The cost of manholes is being reduced by the use of precase sections.

Three phase pad-mounted transformers suitable for supplying medium density loads are now in general use. These transformers are often used in overhead distribution areas and supplied by riser cables from the overhead primary circuits.

Installations have been made of large subsurface transformers in small form-fitting precase concrete vaults. These installations are used for medium load density areas where there are no suitable locations for pad-mounted transformers.

Manufacturers are also working on the development of primary switching and protective equipment for subsurface installation. Such equipment is needed particularly for main feeders through residential areas where pad-mounted installations would be aesthetically objectionable and submersible equipment in conventional manholes would be excessively costly.

As a result of these developments and others, such as the use of aluminum instead of copper cables, the cost of underground distribution in medium load density areas and of undergrounding main primary feeders is being reduced to some extent. However, it is still much more costly than overhead. Despite this premium cost, the use of underground for medium load density distribution is increasing rapidly. Main feeders are being installed underground in some new subdivisions. Some of these developments are also finding application in high load density areas.

Conversion of Overhead to Underground

Progress in making underground distribution economically practicable for new developments,

especially residential subdivisions, has contributed to an increasing interest in the conversion of existing overhead lines to underground. This is a much more difficult problem. It inherently costs much more to replace an overhead distribution system with underground than to build an identical underground system to supply a new development. The contrast is even greater if the significant figures in these two cases are compared. These are the cost of the underground system *minus* the cost to build an equivalent overhead system for the new development, versus the cost of the underground *plus* the net cost to remove the existing overhead system for the conversion.

The inherently higher cost of building an underground system to replace an overhead system is due to a number of conditions that are not normally encountered in new developments. One of these conditions is vehicular traffic in existing streets and driveways, which must not be unreasonably obstructed. This requirement may make it necessary to limit the amount of trench that can be open at one time, to provide temporary covers for open trenches, or to haul away the excavated earth and replace it later with imported fill. Another condition is surface obstructions to excavation, such as paving and landscaping, which are costly to remove and replace. A very important one is subsurface obstructions, such as the existing gas, water and sewer lines. Care must be exercised to avoid damaging these facilities during excavation, and the new underground facilities must be so located as to provide suitable clearances from them. The presence of these obstructions may limit or prevent the use of efficient machine methods of trenching.

Some of the technological advances that have contributed to reducing the cost of underground distribution in new developments are equally applicable to conversions. These include aluminum conductors, polyethylene insulation, pad-mounted transformers where suitable locations for them are available, subsurface transformers where they are not, and joint use of trenches. Directly buried cables or cables preassembled in flexible conduits are usable in many cases.

In order to further reduce the cost of conversions, the principal need is for the development of less costly techniques for installing the cables in the earth as an alternative to conventional trenching and backfill operations. A possible solution is the development of more efficient boring techniques than are now available, so that the ducts or cables can be pushed or drawn through the ground below the level of subsurface obstructions. This would avoid the problems of traffic interference, surface obstructions, and subsurface obstructions that are encountered with conventional trenching methods.

Operation and Maintenance

Procedures for operation and maintenance of underground distribution systems differ from those of overhead systems. Much overhead equipment is designed so that inspection from ground level will indicate whether or not it is in good operating condition. For overhead lines along streets, visual patrol of the circuit simplifies preventive maintenance programs and provides a quick method to determine cause of outage in case of interruption of service.

In contrast, equipment for underground systems is not readily visible. Doors of above-ground enclosures, or covers of below-ground structures, must be removed before the equipment can be seen. Even then it may be difficult to determine if a device is in operable condition, since the equipment may be enclosed to provide electrical insulation and physical protection from environment.

In case of electrical failure of underground cable from causes other than visible damage by digging equipment, it may be necessary to use sophisticated fault locating equipment to pinpoint the location of the fault. Fault location can be a time consuming job and it requires a high degree of skill. Because of the time which may be required to repair faulted underground cable, it is the usual practice to restore service temporarily from another source rather than to delay restoration until repairs are made.

Underground lines are relatively immune to some of the major causes of failures in overhead lines, such as car-pole accidents, damage from wind, ice, and snow storms, and trees and other foreign objects contacting wires. But underground lines have their own causes of trouble, including entrance of moisture, corrosion, cable dig-ins, insulation failures, damage during installation and possible deterioration with age.

Underground equipment must be designed for long life in below-ground enclosures that may be occasionally or continuously filled with water containing contaminants. Underground cables and equipment are both vulnerable to the entrance of moisture through any flaw in splices, terminations, cover gaskets, operating handles, bushings, etc. Underground corrosion affects equipment tanks, cable shielding wires, and any exposed metal.

Experience in widely-separated areas indicates that corrosion of subsurface transformers can be a serious problem. Mild steel tanks with protective coatings have failed in a few months. It appears that greater care in the maintenance of coating integrity or the use of higher cost stainless steel is required. The use of cathodic protection methods may be necessary in some locations.

Studies that have been made of the expenses of operating and maintaining conventional underground systems indicate that they are higher than for equivalent overhead systems. It is probable that operation and maintenance expenses for the newer types of underground systems will be higher than for equivalent overhead, but data for quantitative comparisons are not available.

SECTION 4—ENGINEERING AND CONSTRUCTION TECHNIQUES

Distribution systems must be planned, designed and constructed to provide adequate and satisfactory service to the growing loads at minimum cost and with due regard to environmental considerations. Effective performance of these engineering and construction functions requires the service of an increasing number of competent and experienced distribution engineers and the application of efficient modern equipment and techniques. The equipment and techniques used vary to some extent because of different load, environmental, and other conditions, but they also have much in common throughout the electric utility industry.

Engineering

Distribution engineering includes a large number of activities necessary to plan and design the system from the substation to the customer's equipment. It is not within the scope of this report to identify and describe all of these activities and the numerous technical problems that they involve. However, there are certain major activities that are basic to efficient planning and design. Much of the detail work of distribution planning can be performed by technicians thus releasing engineering manpower for more technical work.

Standards

The piecemeal growth of a distribution system involves the repetitive use of similar engineering analyses and similar component designs, and the use of large quantities of identical items of material. Extensive use of engineering, construction, and material standards is essential to minimize costs. Principal types of standards include the following.

Industry material standards.—are necessary to achieve the economies of volume production by reducing the number of material items used by utilities to a practical minimum. Organizations that are active in this industry standardization work include manufacturers associations such as NEMA, utility associations such as EEI and professional societies such as IEEE. Joint committees representing two or more organizations perform some of this standardization work. Many of the standards thus developed are adopted as USA Standards through the procedures of USASI, which require a consensus of all interested industry groups.

Individual utility material standards.—are an essential tool for economical purchasing, stocking, and application of materials by utilities. Most utilities have their own standard specifications for the items of material that they purchase in quantity. These are preferably based upon industry-wide standards, but include only those items that the utility wishes to use for its own system.

Construction standards.—are used to specify the materials that are to be used to build standard distribution system components, and how they are to be assembled and installed. Use of such standards avoids much repetitive work that would be necessary to design each component individually.

Engineering standards.—are guides for distribution system planning engineers in order to minimize the work involved in making routine or repetitive planning decisions. They provide data and criteria for such purposes as estimating new customer loads, sizing conductors and transformers, spacing substations and line transformers, and providing satisfactory voltage regulation.

Generalized Planning Studies

Comparative studies of alternative distribution system designs are made in order to determine the optimum designs to supply loads of different den-

sities and other characteristics. Variables that are involved in such generalized planning studies may include system voltage levels, size and spacing of substations, size and spacing of line transformers, sizes of primary and secondary circuit conductors, circuit arrangements, etc. Often many alternative system designs are compared, which involves large amounts of detailed calculation. Digital computers are often used for this work.

These studies provide the basic information required for major decisions, such as the adoption of a new higher voltage level for the system, or for engineering standards to guide system planners.

Area Planning Studies

A basic function of distribution engineers is to develop plans for the orderly and economical reinforcement of existing distribution systems to provide capacity for the growing load requirements. Such plans include the construction of new substations and primary feeders, and increases in capacity of those already existing. They may also include new transmission lines to supply the substations and increases in primary distribution voltage levels. Decisions as to the capacity, location and timing of the facilities to be built or reinforced are based on studies of this type.

Facilities must be planned with sufficient lead time so that they can be authorized, designed, and built in time to meet the load requirements. Adequate lead time is needed to acquire new substation sites and transmission line rights-of-way and to obtain any necessary governmental approvals to build the facilities. The increasing scarcity of suitable sites and the growing emphasis upon environmental compatability have greatly increased the lead time requirements for new facilities in many areas.

In order to determine the optimum plan, a number of alternative plans are usually compared. This sometimes involves extensive detailed calculations of costs that can be performed most efficiently by digital computer.

Engineering Information Systems

To anticipate the need for changes and additions to the distribution system and to plan these changes and additions, distribution engineers require a large amount of reliable and up-to-date information. Most of this information falls into three categories:

The physical and electrical characteristics of the existing distribution system, including any additions to the system that are already planned.

The location and magnitude of existing and anticipated loads to be supplied by the system.

Past experience with failures of system components and interruptions to customer service.

This information must not only be accumulated and kept up-to-date, but must be correlated and analyzed to determine the need for increases in system capacity and for improvements in voltage regulation and service reliability. Because a distribution system consists of such a large number of components and serves so many individual customer loads, the total volume of data and the number of changes that must be made in it each year are very large.

In the past, this information has generally been recorded manually on maps and other office records and analyzed by conventional methods. A large expenditure of technical and clerical manpower was necessary to keep the information up-to-date and to analyze it by these methods.

Utilities are now using digital computer techniques to reduce these manpower requirements, to provide more complete and current records, and to analyze the information more thoroughly. Computer programs and procedures have been developed to monitor and analyze loads on transformers, load and voltage conditions of radial feeders and secondary networks, area load densities, and experience with equipment failures and customer service interruptions. Some of these computer applications are described in more detail below.

Computers

The use of computer systems for purposes directly associated with distribution is relatively recent. It is expected that uses in this area will be vastly expanded in the coming years. Before forecasting probable future computer applications it is necessary to look briefly into the past development of systems and uses, even though they are only partially distribution oriented.

Digital computers were initially applied by utilities in accounting as successors to the card tabulating systems, and in engineering where the digital computer succeeded the analog computer for load flow and short circuit studies.

The advantages of the computer for solving

engineering problems, requiring a large amount of repetitive calculation with a high degree of accuracy, were quickly recognized. Many utility engineering departments set up computer applications groups that have developed a wide variety of programs for solving engineering problems. Programs are exchanged on an industry-wide basis.

Use of the computer has spurred the development and increased use of systems analysis and operations research techniques. The possibilities of using these techniques to simplify, integrate and automate the reporting and recording of data, and the automation of its compilation and analysis, are still under investigation. Some utilities are moving rapidly in this area and others have made various degrees of progress.

Applications Related to Distribution

A partial list of present computer applications in the distribution area follows:

System Characteristics.—Programs are available to calculate line and transformer impedances, ampacities of insulated cables, and other system parameters.

Load Forecasting.—Many systems of varying degrees of complexity have been developed for short and long range forecasting of future loads from historical load growth data.

Data Banks.—Load data and system parameters are being stored on magnetic tapes and kept up-to-date so that computer studies can be made of systems without special investigation and preparation of input data.

Radial Circuit Analysis.—Procedures and programs have been developed for analyzing load and voltage conditions on radial primary feeders identifying overloaded feeder components and substandard voltage conditions, and determining the effectiveness and cost of alternative plans to correct these conditions. Power losses can be computed and evaluated in determining the most economical corrective measures.

Secondary Network Analysis.—Load flows and voltage conditions in secondary network systems with each primary feeder out of service can be computed, unsatisfactory conditions identified and alternative corrective measures evaluated and compared by digital computer.

Transformer Load Management.—Procedures and formulas have been developed for computing the demands on line transformers from the kilowatt-hour consumption during the billing period of the customers supplied from each transformer. This makes it possible to monitor the loading of all transformers without costly field measurements. Overloaded and underloaded transformers are identified in the computer printout for appropriate action. Information is provided for determining whether transformers have capacity to supply proposed load additions.

Reliability Analysis.—Many utilities have developed procedures and programs for reporting equipment failures and service interruptions and for analyzing them by digital computer. Interruptions are analyzed as to cause, location, and groups of customers affected. Equipment failures are identified as to type, make, age, and cause of failure. Areas or customer groups with unsatisfactory interruption experience and items of equipment with abnormally high failure rates are identified for appropriate action.

Work Measurement.—Systems of relating work accomplished to the time required to accomplish it, and comparing the result to some theoretical or empirical norm, have been developed. In some utilities, these programs have been integrated with work or maintenance order systems.

Work Order Preparation.—Systems have been developed for the preparation of work orders from basic work units. The use of these units of material and labor enables a computer to translate the work request into material and labor requirements, to estimate the cost, to compare this with budgeted funds and to provide material lists and work authorization to be forwarded to the requesting party. In addition, this system provides for semi-automatic accounting for completed work.

Scheduling.—Some utilities have developed relatively sophisticated systems for scheduling and controlling large construction and maintenance projects.

Future Development

The development of high speed computers, large capacity random access storage facilities, and relatively low cost remote terminal equipment, combined with advanced methods of systems analysis and increasing management support, has set the stage for improvement in distribution engineering, operating and construction methods and controls.

Input documents for accounting, engineering and operating systems can be integrated and improved. Optical scanners can be used for direct entry of data in some systems, bypassing keypunching and eliminating keypunch errors.

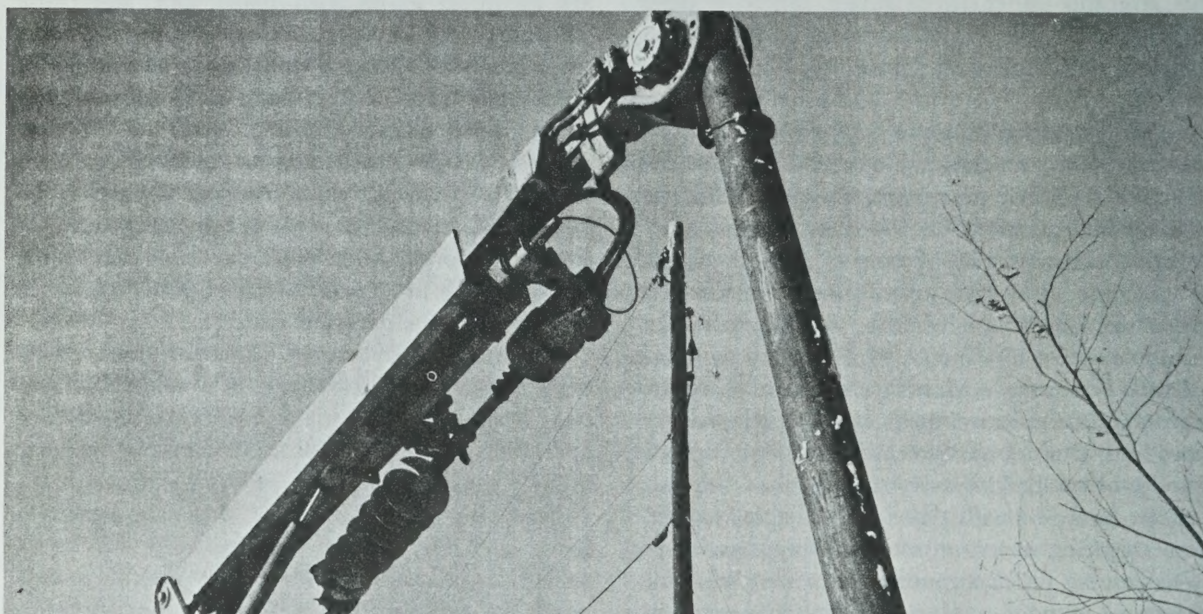
Record files can be analyzed and re-evaluated. In many cases, they can be integrated with those of other systems and placed on magnetic tape or, in some cases, on random access storage attached to on-line computers for access by remote terminal.

Remote terminals can be used for input and output of orders and information, reducing the processing time of requests for work authorization, and making available recorded data for use where needed.

Grid coordinate mapping systems can be used to index material on data files. This will enable circuit maps to be produced and maintained by plotter, provide an interface between files, and facilitate studies.

Distribution circuits can be analyzed on a routine basis, with trouble spots identified by exception reporting techniques, and complete analysis of any circuit available when needed.

Using the "work unit" concept, existing automated work order systems can be extended and improved. Integration of these systems with maintenance order systems, budgetary control systems, and comprehensive work and resource scheduling systems can be effected. Resources of men, money, machines and material can be scheduled and



Line Truck with Corner Mounted Derrick and Earth Borer.

Aerial Bucket on Insulated Boom with Boom Extension.

controlled from the planning stage through the completion of construction.

Responsibility reporting can be extended to furnish up-to-date information to every level of management on the work for which it is responsible.

Sensors installed on distribution feeders can relay data on circuit conditions to central or substation computers, which can analyze troubles, relay problems to restoration centers, and initiate corrective actions.

Meters can be read by polling techniques from central computers over the customers telephone line, files can be updated, and bills automatically calculated and printed.

Some of these applications are not presently economically feasible. It is unlikely that all of these applications will be used by all utilities or to the same degree in all cases. Smaller utilities will have less need for complicated control systems than will the larger, and economic evaluation will, in the final analysis, determine the nature and extent of the programs adopted by any individual company.

Construction Equipment Mechanization

There have been many improvements made in construction and maintenance techniques of electrical distribution systems in an effort to offset steadily rising labor costs. New and improved tools and equipment have probably made the largest contribution toward improving labor productivity.

Overhead Line Equipment

Modern line trucks are equipped with power operated booms, earth borers, tampers, winches, compression tools, two-way radios, and a variety of hand tools which make it possible to reduce the size of crews.

Truck mounted derricks with the heavy duty earth borers have increased production and reduced pole setting costs up to thirty percent. They can be utilized to perform most pole top construction work and material handling more safely, faster and more easily.

Aerial baskets, or buckets, either single or double, are available to enable men to be quickly placed in a safe and comfortable working position. This not only saves time, but often makes it possible to utilize the talents and experience of lineman for many more years than is otherwise possible.

Aerial baskets on insulated booms can be used to advantage when working on energized high voltage lines. In many cases, insulators, cross-arms, and poles have been replaced, and damaged sec-

Trencher.

Auger.

tions of conductors repaired, without de-energizing the lines and interrupting service. Considerable savings in costs and man-hours have been realized. In addition to their contribution to efficiency and safety in construction and maintenance, this equipment contributes to the reduction of outage time in emergency situations.

Underground Line Equipment

Over the years, tools and equipment have been developed to help reduce construction costs of underground distribution systems that serve downtown commercial areas. However, underground distribution to serve suburban commercial areas and residential areas is entirely different from that required to serve downtown commercial areas with respect to construction practices, techniques, and equipment needed. Progress in the development of suitable construction equipment can be expected to continue because of the expanding market and the combined efforts being made by the utilities and the manufacturers.

Digging and backfilling of a trench is a common requirement for nearly all underground installations and the mechanization of this operation has received considerable attention. Several different types of equipment are available to accomplish this purpose. They generally fall into the category of trenchers, cable plows, back hoes, augers and moles.

There are many versions of trenchers with respect to size and auxiliary equipment. A trencher unit is shown in the illustration. A small back hoe can also be used on this type of equipment.

The cable plow, may be mounted on a small trailer, pulled by a tractor, or be an integral part of a complete cable laying machine. In either case, the plow is designed to open a narrow slot in the earth and is well adapted to opening the slot and laying the cable in a single operation.

The back hoe is fundamentally a small excavator which is usually mounted on a tractor and is well adapted to digging trenches to accommodate electric cables. A back fill loader type blade is mounted on the front end of the same tractor.

Augers and moles are designed primarily to open holes under streets, sidewalks, railroads, and other obstructions with a minimum amount of damage to property and inconvenience to the public. The large horizontal earth boring units are capable of boring a hole 36 inches in diameter. Smaller units can bore an 8 inch hole.

Moles open a small hole by compacting the

Impulse Testing Equipment.

soil. The diameter of the hole can be increased up to 3 inches by means of a reamer. A cable can be attached to the reamer and pulled into the hole as the reamer is withdrawn.

The type of equipment which can be used depends upon accessibility to the proposed cable route and whether or not the route is free of subsurface obstructions such as gas, water or sewer lines, and rock. Under ideal conditions, a mechanized "train" can be used to open the trench, lay the cable, and backfill in one operation.

Fault and Cable Location Methods

The visual fault locating and inspection techniques which are used with overhead conductors are not applicable to underground cables. There are several methods available for determining the location of troubles and the condition of an underground cable. No one method is adaptable to all situations. It is necessary that several different methods be available in order to provide for the location of all types of cable faults.

Much of the modern test equipment is electronic in nature and relatively easy to operate when compared to past methods. It does, however, require a skilled operator to interpret the test results obtained from use of the equipment.

The high voltage impulse "Thumper" is a capacitor discharge system that has been used for many years to locate trouble on underground systems. The capacitor is discharged into the faulted cable repeatedly. The impulses can be picked up through the use of earphones or meters connected to probes or explorer coils at the location of the fault.

Radar type equipment sends out a signal on a faulted cable and the time required for the signal to be transmitted to and reflected back from the fault is observed on an oscilloscope. This time is calibrated in distance to indicate the location of the fault.

In some cases, a high frequency tone is placed on a cable. By using probes, meters, and earphones, it is possible to detect the location of the fault through the change or loss of tone. This type of equipment is well adapted to locating faults on direct buried cable used in underground residential distribution.

Locating a Fault.

There are several other types of fault locating equipment available that have been used successfully to locate underground failures. Similar equipment is used to proof-test cables after they have been repaired to insure their operating ability. Even with the best of available equipment, location of faults on underground is much more complicated, more time consuming, and more costly than on overhead.

Joint Construction Practices

The joint use of poles by electric and communication utilities has been a common practice for many years. Generally, the joint use of poles is in accordance with a formal agreement or contract between the participating utilities. Joint use contracts conform to the National Electrical Safety Code and usually follow recommendations outlined in EEI Publication No. M 12, a Report of the Joint Committee on Plant Coordination of the Edison Electric Institute and the Bell Telephone System. In addition to the economic advantages, the joint use of poles is beneficial from the standpoints of aesthetics and traffic safety.

As yet, joint use of underground distribution facilities by the various utilities is not as common as with overhead distribution. Underground distribution offers the opportunity for more utilities to participate in joint use with appreciable savings. Recent surveys indicate that, although trenches are being shared by many electric and communication utilities, joint use with gas and water utilities is not presently common practice. Where the electric and gas service are provided by the same utility, electric, gas and telephone facilities are often installed in the same trench.

Supplement 2 to The National Electrical Safety Code issued in March, 1968, specified the requirements for direct burial of underground power and communication cables in the same trench with no deliberate separation, a practice commonly referred to as random separation. Joint occupancy

practices and procedures for installation of underground in a common trench have been thoroughly investigated. EEI Publication 68-62, dated June, 1968, a Report of the Joint Subcommittee to Study Buried Distribution Systems of the EEI and Bell Telephone Systems, constitutes an analysis of primary cable fault tests and evaluation of experience with random separation. A few utilities indicated they have progressed to the point where joint agreements have been established.

In order to realize the full benefits of joint use of trenches for underground distribution, careful coordination of work to be done by all participating parties is essential. Otherwise, a large part of the expected savings are lost due to the excessive labor costs caused by delays and improper arrangements.

There is a great difference in the construction of an overhead and an underground system. However, the experience and benefits obtained through the joint use of poles for the overhead system and experience with underground construction to date indicates that favorable results will be realized through joint use of trenches for underground.

SECTION 5—RESEARCH AND DEVELOPMENT

Distribution systems are in a continuing state of evolution and development. Basic research to explore the application of new materials and development activity to determine optimum application of both new and existing materials are now being carried on. These activities should be continued and accelerated in the future to meet the expected utility industry needs, particularly the needs of underground distribution systems.

Current Status

Review of current research and development activity indicates that a considerable amount of work is being done by manufacturers and by the electric utilities.

Work by Manufacturers

It has been traditional for distribution system equipment to be developed by the manufacturers of the equipment in accordance with the indicated requirements of the utilities. The research necessary to develop the basic materials has been done by the manufacturer of the distribution devices or by the supplier of the materials used in the devices. When a decision has been reached to proceed with the development of new equipment, the manufacturer usually consults with the utilities to confirm that the device is needed and will have utility acceptance, since sales of such equipment support the research and development effort.

A process of selection has resulted. Many products have been offered and those that received industry acceptance have remained on the market. Those that were not purchased in quantity have been withdrawn from the market. With the relatively slow changes in overhead distribution systems, development by manufacturers of new equipment has met the needs fairly well, except where new devices were desired for changed conditions. Utilities that adopted primary voltages higher than those in common use have been forced to pioneer in equipment development and to encourage manufacturers to produce the devices needed. The same procedures were required to obtain equipment of better appearance. When sufficient usage was obtained, the process of selection began to operate.

As the installation of underground systems in residential areas increased, a need developed for equipment for these underground systems. The initial effort by utilities was to place overhead system devices in above-ground enclosures. Early transformer installations for underground, or semi-underground, residential systems consisted of overhead type transformers and protective devices with exposed bushings placed in concrete or metal above-ground enclosures.

About ten years ago, transformers integral with above-ground enclosures, designated as pad-mounted units, were developed. The efforts of one utility, active in residential underground, spurred the development of this type of transformer. More recently, submersible transformer units designed for installation in below ground enclosures were developed for residential underground systems.

Cables with extruded insulation, which do not include a metallic sheath, have been developed for use on underground primary systems. Factory made splice kits and terminations for primary voltages, which can be installed by personnel with minimum training have been developed. The combination of satisfactory cables and termina-

tions has made possible the present concept of residential underground systems.

Little progress has been made in the development of sectionalizing and protective devices designed specifically for the requirements of underground systems of the residential type. This is particularly true for primary voltages higher than the predominant 15 kV class.

With increasing load densities, many utilities can justify the need to increase primary voltages above 15 kV so as to reduce the number of distribution circuits and substations required. The equipment necessary for flexible operation of 23 kV and 34.5 kV underground systems in suburban residential and commercial areas is not presently available. The electric utility industry finds itself in the position of being unable to make efficient use of voltages higher than 15 kV in underground distribution systems because the development of sectionalizing and protective equipment suitable for operation on the higher voltage primary systems has not kept pace.

Work by Utilities

Many electric utilities have carried out individual research projects on distribution system problems. The results of the research work have generally been reported to the industry in papers presented at regional and national meetings.

The Edison Electric Institute (EEI) has requested the utilities to report research projects in process. These projects are listed by categories in an EEI publication entitled "Survey of Research". The issue of April 1967 is a voluminous report (456 pages) which covers virtually every part of all sectors of the electric utility industry. There are many projects listed pertaining to distribution, particularly underground systems. Under "Transmission and Distribution" the subheading "Materials and Equipment" has a sectionalized grouping for underground systems. Under "Cables and Accessories" there are 22 projects listed. The heading "Cable Joints and Accessories" covers 24 projects. There are also 24 projects listed pertaining to transformers and other items of underground system equipment.

EEI acts as the reporting agency for research projects performed by individual electric utilities. As yet, no attempt has been made to coordinate or direct the research activity of the member companies to assure coverage of the subjects and to avoid duplication of effort.

Within the past few years, EEI, representing the investor-owned utilities, has combined with groups representing the publicly-owned utilities, and with governmental bodies, in the formation of the Electric Research Council (ERC). This council represents all segments of the electric utility industry.

The principal aim of ERC is to encourage and promote research in those areas where no other activity is imminent. Usually these projects are industry wide in scope and require extended time to develop answers on a long range basis. ERC sponsors and underwrites a major portion of the costs on such projects. Projects presently under investigation include research on air pollution, development of battery systems for the electric car, extensive investigation of D C. transmission and research on D. C. circuit breakers.

In the underground area, there is a program to investigate the development of new insulations for high voltage transmission cable systems. In addition, entirely new cable systems, with external cooling, operating at temperatures as low as a few degrees above absolute zero, are being considered. To determine the practicality of the proposed new systems in terms of actual system operation, a new test facility is under construction at Waltz Mill, Pennsylvania. In this facility, cable systems will be given long time tests at voltages, currents and temperatures in excess of rating. Projects now scheduled for the Waltz Mill facility include new designs for 500 kV cable and improved designs for lower voltage transmission cables.

None of the projects sponsored by ERC are directly related to equipment for use on distribution systems. It is expected that some of the developments for high voltage transmission systems may eventually have some application to the lower voltage distribution systems.

Suggested Future Activity

To supply the higher load levels of the future it is necessary to increase the load carrying capability of distribution system components as outlined in the foregoing sections of Part II. This will require an accelerated program of research and development geared to the requirements of distribution systems.

Distribution Voltage Levels

There are two general methods of expanding the capability of distribution circuits, increase in conductor size or increase in circuit voltage to

allow more load to be carried with the same conductor size. Since there are practical limits to conductor sizes in both overhead and underground systems, higher distribution voltages are necessary to obtain large increases in circuit capability.

Increase in voltage has been the method generally used to raise the capacity of primary systems. The first alternating current primary system operated at 1000 volts. The predominant primary voltages at this time are in the 15 kV class. Use of 23 kV and 34.5 kV for overhead distribution systems is increasing rapidly.

Because of the lack of suitable 23 kV and 34.5 kV equipment for underground use mentioned above, and in order to initiate the use of the higher primary voltages some utilities are improvising by using devices developed for the 15 kV voltage class on 23 kV systems. In some cases, it has been necessary to choose a 23 kV level for new primary systems rather than the higher 34.5 kV level because equipment for the latter is not available.

With the increase in primary voltage on overhead or underground systems, the cost per step-down transformer installation increases. To realize the economy of the higher primary voltage, it is necessary to use fewer step-down transformers of larger capacities. This in turn requires higher secondary voltages for an economical overall distribution system.

The need for secondary voltages higher than the present 120/240 volt single phase, or 120/208 volt three phase levels has been recognized for a long time. To meet this need for three phase loads, the 277/480 volt level was initiated several years ago. This voltage is now widely used for commercial and industrial loads, both in downtown sections and in suburban areas.

The advantages of corresponding increases in the 120/240 volt single phase voltage level, normally used for residential service, have been presented at industry meetings and published in the technical press. High-use residential customer demands are now many times the values prevailing when the voltage was selected. Yet the secondary voltage has not been increased to keep pace with the growing loads and the higher primary voltages.

Utilization voltages for fixed-wired, built-in, major residential appliances would need to match the higher secondary voltages to eliminate the requirement for a relatively large transformer at each house to step down to utilization voltages. Continuation of 120 volts as the utilization voltage for the small plug-in devices, supplied through a small step-down transformer, would probably be the practical arrangement.

Underground System Equipment

The immediate need for new equipment for underground distribution systems is recognized by utility engineers in all parts of the country. From the equipment manufacturers standpoint, it may be said that a device designed to meet the requirements of one utility will not necessarily be accepted by other utilities. A group approach to determine the consensus of engineers representing a number of utilities seems indicated and is being attempted.

Efforts are now being made to set up groups to work toward the development of equipment and related operating procedures for underground distribution systems. Regional groups have been formed in several sections of the country. Other groups with wider geographic representation have been formed by consulting engineering organizations. Work is being done on a national basis by electric utility industry committees.

Because of the pressing need for underground distribution system equipment, it is suggested that group activity to facilitate the development of this equipment be continued and accelerated at regional and national levels. Effort should be made to coordinate the work of the various groups to eliminate duplication.

Discussions, in some detail, of the types of equipment needed for underground residential systems are included in Appendix C.

Equipment Testing

Testing of new distribution system devices prior to installation, under conditions simulating actual operation, could be of benefit to electric utilities. There would be at least two definite advantages. First, the manufacturer would be able to determine that a new device is designed for the conditions which it will encounter in operation. Second, the user could install a device with more confidence after it has passed a qualification test. The devices would be tested in a field laboratory where failure would not be of consequence, rather than in a utility system where failure could result in customer outage.

Tests have been performed at Cornell University, under the auspices of EEI, on high voltage transmission cable systems. More extensive tests on transmission cable systems are projected for the Waltz Mill test facility. Thus a precedent has

been established for the accelerated life testing of power system components under conditions simulating actual operation. This is in contrast to the much slower procedure of placing in service new devices with designs based upon laboratory findings and, in effect, testing the new devices in actual system operation.

Automated Procedures

As distribution system loads continue to increase, and arrangements of the circuits become more complex, the need increases for fast and accurate switching to isolate equipment which fails in service. The objective should be to confine the effect of the failure to the smallest practical area, to restore service to the remainder of the system, and to indicate the location of the failure so that repair procedures may be initiated as soon as possible.

Automatic controls may be used for sectionalizing switches as described in Appendix C. As the network of circuits becomes more complicated, it may be advantageous to install communication channels for remote indication of switch position, or for control of switch operation from the distribution system dispatching center or other convenient location.

Use of Computers

A further refinement in distribution system operation is the use of computers for the control of sectionalizing devices. With the computer it should be practicable to pinpoint the location of system component failure, to select the optimum arrangement of switches to isolate the failure, and to restore service to all portions of the circuit not affected by the failure within a very short time period.

Computer control of distribution circuits should be quite similar to control of manufacturing operations in industrial plants. Greater sophistication of programming may be necessary to analyze all of the conditions relating to component failure in a relatively complex network of distribution circuits.

An added advantage of computer control, or remote indication of switch positions, would be immediate knowledge of fault location so that corrective measures could be initiated without delay. Without indication of fault position at the dispatching center, calls from customers without service are the first indication of a failure of a distribution circuit component.

The possibility of computer control in the future should be considered in circuit arrangement and in selection of sectionalizing devices. Provision should be made for later addition of modules to sectionalizing devices to allow remote or computer control if desirable. The possibility of incorporating control circuits in primary cables should be considered.

Initial Objectives

Initial objectives for research and development programs should be the consideration of procedures and equipment needed for the expected expansion of underground distribution systems. These needs are outlined in some detail in Appendix C.

An activity of immediate importance is the development of submersible sectionalizing and protective devices for underground primary distribution circuits. These devices are needed at this time to meet the reasonable requirements for reliability of underground distribution systems. The need will become much more critical in the near future. More efficient methods for installation of underground equipment should be considered.

For universal application, the devices developed for underground systems should be suitable for operation in a variety of circuit arrangements. A modular approach could accomplish this objective, but might be more costly because of the larger number of submersible enclosures and connections required. It is not to be expected, nor is it desirable, that all electric utilities use the same types of circuit arrangement in all service areas. Differences in geographical features and in load requirements make it necessary to have flexibility in the application of underground distribution system devices.

PART III—DISTRIBUTION ECONOMICS

Throughout the history of the electric utility industry in the United States, there has been a steady downward trend in the average cost of electric energy per kWh sold to customers. The decreasing cost trend of this most flexible and convenient form of energy has been a major factor in both the rapid growth of the industry and the rising national standard of living. It is desirable for the future of the industry and of the nation that it be continued.

Since approximately 40 percent of the investment of electric utilities is in distribution facilities, the trend of distribution system costs will be a major factor in determining what customers must pay for electric energy in the future.

The cost data and forecasts in this part of the report are totals and averages for all electric utilities in the contiguous United States. No attempt has been made to break them down by region, type of ownership, or other system of classification. Unit costs of individual utilities have in the past and will in the future vary considerably from the national averages because of difference in climate, topography, load density, load characteristics, growth rate, type of ownership, size of utility, and other factors.

For the purpose of comparing costs at different points in time, annual costs are expressed in cents per kWh, using as a base (except in Table III-j) the total kWh sold to all ultimate customers of the industry. This base includes the energy delivered to a relatively small number of large customers directly at transmission voltage or through single-customer substations connected directly to transmission systems. The amount of energy sold to such large customers is not known, but is estimated to be on the order of 25 percent of all the energy sold. Therefore, if only the energy delivered through distribution systems were used as the base, all costs per kWh (except those in Table III-j) would be about one-third higher than they appear in this part of the report; but their relative magnitudes would remain as indicated.

The development of the cost data presented in this part is set forth in more detail in Appendix B.

SECTION 1—PRESENT COSTS AND COST TRENDS

This section considers present (1967) distribution costs, historical cost trends from 1952 to 1967, and the projection of these trends to 1990. It also considers the factors that have influenced the historical trends and how they may be expected to influence future trends.

Present Costs

The estimated cost of distribution in the United States in 1967 is summarized in Table III-a.

In Table III-a, the figures for investment in overhead and underground lines include line transformers and services. "Other components" include meters, installations and leased property on customer's premises, and street light and signal systems.

Overhead lines are by far the largest component of distribution system investment, representing about 55 percent of the total. Overhead and underground lines together represent more than 70 percent of the total.

The annual cost of distribution consists of fixed charges on investment and operation and maintenance expenses. Fixed charges include return on invested capital, depreciation, taxes, and insurance. In the 1964 National Power Survey, the weighted average fixed charge rate for distribution for all segments of the electric utility industry was estimated by the Federal Power Commission to be at 12.0 percent of distribution investment. Since that survey was made, taxes and the cost of capital have increased substantially. A revision of this weighted average fixed charge rate had not

TABLE III-a

1967 Distribution Costs

	Millions of dollars	Dollars per customer	Cents per kWh sold
Investment:			
Distribution substations	5,890		
Overhead lines	18,510		
Underground lines	5,450		
Other components	3,580		
Total distribution investment	33,430	497	
Annual Costs:			
Fixed Charges at 13.5% of Investment	4,520	67.10	0.409
Operation and maintenance expense	1,260	18.70	.114
Total annual cost	5,780	85.80	.523

been completed by the Federal Power Commission at the time this report was prepared. For the purpose of computing annual costs in this report, the Distribution Technical Advisory Committee has used a weighted average fixed charge rate of 13.5 percent. The fixed charge rates for investor-owned utilities are higher, and those for publicly and cooperatively owned utilities are lower than the weighted average for all segments.

In 1967, the industry sold an estimated total of 1,103 billion kWh to 67.3 million ultimate customers, an average of 16,400 kWh per customer. As indidated in Table III-a, the annual cost of distribution in that year is estimated at 5.78 billion dollars, which amounts to $85.80 per ultimate customer or .523 cents per kWh sold.

Historical Trends

During the 15 year period 1952–67, average kWh use, distribution system investment, and distribution operation and maintenance expense per ultimate customer served were increasing annually. However, because kWh use was increasing more rapidly than either investment or operation and maintenance expense, the trends of distribution investment and expense per kWh were downward.

These trends and the future cost per customer and per kWh that would result if they were to continue to 1990 are summarized in Table III–b. The figures for future kWh use per customer are from the forecasts of the Regional Advisory Committees. Those for future investment and operation and maintenance expense per customer were obtained by extrapolating the historical trends of these costs.

The 1970, 1980, and 1990 costs in Table III–b are designated "extrapolated" to indicate clearly that they are not intended to be forecasts of future cost levels. They are simply the levels that would

TABLE III–b

Extrapolated Distribution Costs

[Based on simple projection of past trends, without adjustment for factors expected to modify those trends.]

	Actual		Extrapolated		
	1952	1967	1970	1980	1990
kWh per customer	7,650	16,400	19,200	32,100	53,600
Dollars per customer:					
Distribution investment	247	497	558	835	1,250
Fixed charges at 13.5% of investment	33.30	67.10	75.30	112.70	168.80
Operation and maintenance expense	12.90	18.70	20.10	25.50	32.10
Total annual cost	46.20	85.80	95.40	138.20	200.90
Cents per kWh:					
Fixed charges	0.436	0.409	0.392	0.351	0.315
Operation and maintenance expense	.169	.114	.105	.080	.060
Total annual cost	.605	.523	.497	.431	.375

be experienced if these costs continued to follow the historical trends until 1990. Long range forecasting of costs is subject to many uncertainties, and it is improbable that these costs will closely follow the extrapolated trend curves through this period. The past trends of distribution costs have been influenced by a number of factors, some of which tend to decrease costs per kWh and others to increase them. In order to develop probable forecasts of future cost levels it is necessary to examine each of these factors and consider whether its influence upon the future cost trends will be similar to its influence upon the past trends.

Factors Tending to Reduce Costs

The two principal factors that have made possible the decreasing trend in distribution cost per kWh are increasing load density and technological progress.

Increasing Load Density

Historically the load densities on distribution systems have been increasing as both customer densities and load per customer have increased. The effect of this increased load density is to permit more energy to be distributed per mile of distribution line, per substation, per line transformer, etc. The capacities of these components must be increased to transmit the increased energy, but higher capacity components cost less per unit of capacity. The effect of increasing load density in reducing the unit cost of energy is reflected in most utility rate structures in a decreasing cost per kWh as energy use per customer increases. In some cases, rates in areas of high customer densities are lower than in areas of low customer density.

It is indicated in Part I, Section 2, that the distribution system customer growth between 1970 and 1990 is expected in the higher density categories of nonfarm residential customers and commercial customers rather than in low density rural areas. Also, average energy use per customer is expected to increase more than 250 percent for non-farm residential and more than 300 percent for commercial customers. It is expected that increasing load densities will continue to influence the trend of distribution costs per kWh in the downward direction. It cannot be assumed that the magnitude of this influence will be as great as it has been in the past, since any factor of this sort must eventually reach a point of diminishing economic returns.

Technological Progress

Technological progress has many aspects which are discussed in detail in Part II of this report. Of those that have contributed to the downward trend of distribution costs in the recent past, probably the most important are development of higher capacity components, development and application of lower cost materials, improvements in manpower efficiency, and optimization of system designs.

Primary circuit capacities in particular have been increased by the use of larger conductors, higher power factors and, most importantly, higher primary distribution voltages. In combination with increased load density, this has made the use of larger substations supplied at higher transmission voltages economical, thereby reducing substation (and also transmission) cost per kWh. These trends are expected to continue but may also be approaching a point of diminishing returns. On some systems, overhead conductor sizes are approaching practical limitations and power factors have been raised to approximately unity. As primary circuit voltages are increased, the unit costs of line transformers and line switching and protective equipment increase and tend to limit potential savings from this source.

During the past 15 years, technological advances such as the development of lower cost power capacitors, the substituting of aluminum for copper conductors, and the use of smaller and more mechanized construction crews, have tended to reduce overhead distribution costs. Since overhead was the predominant type of distribution during this period, these economies were reflected directly in the decreasing trend of total distribution costs per kWh.

It has now become evident that underground distribution will increasingly be substituted for overhead in the future. The emphasis in research and development has switched from overhead lines to underground, and reductions in the cost of overhead line components are expected to be more limited in the future than in the past.

Substantial cost reductions in underground have already been achieved by such developments as pad-mounted and subsurface transformers, lower cost cables, and direct burial of cables. Aluminum conductors are now being substituted for copper in underground applications and trial installations of still lower cost sodium conductors are being made. Other possible ways of reducing underground costs are receiving intensive study.

The trend to underground distribution is considered in Section 2 of this part of the report, as a major factor tending to increase future distribution costs. Future reductions in the cost of underground distribution are considered as modifying this impact of the underground trend upon the total cost of distribution. It would be taking credit for these cost reductions twice if they were also to be considered as factors that will tend to prolong the decreasing trend of total distribution cost.

Other sources of cost savings that apply to both overhead and underground systems are developments such as the use of radio communication, supervisory control, automation, and digital computers. These modern techniques facilitate more efficient use of engineering, construction, maintenance, operating and clerical manpower. The use of computers also facilitates optimization of system designs because of the greatly increased capability to analyze large masses of data and to compare alternative plans. Economies from these sources have not been exhausted.

In summary, it is expected that the same factors that have influenced distribution costs in the downward direction in the past will continue to do so in the future, but probably with some decrease in effectiveness.

Factors Tending to Increase Costs

The principal factors that influence the trend of distribution costs in the upward direction are rising prices of materials and labor, increasing standards of service reliability, increasing cost and difficulty of acquiring properly located substation sites and increasing costs of meeting location and appearance criteria for both lines and substations.

Material and Labor Costs

Over the 15-year period 1952–67, the Handy-Whitman Index of Distribution Plant Costs increased at an average annual rate of about 2.4 percent. This index is a weighted average of material and labor costs to construct new distribution facilities of all types. Labor costs, which are the principal component of operation and maintenance expenses, were rising at an even more rapid rate. The upward trend of material and labor costs is expected to continue, at a rate that may be either higher or lower than the average rate during the past 15 years.

Service Reliability

The trend toward higher standards of service reliability tends to increase distribution costs by requiring more provision of alternate facilities, reserve capacity, automatic switching, etc., in order to prevent service interruptions or to limit their extent and duration. The use of higher capacity components tends to make such provisions more necessary, because outages of these larger components can affect more load and a greater number of customers; or more costly, because a larger alternate facility or more reserve capacity is needed. The trend to higher reliability standards is expected to continue.

Substation Sites

The investment in land for substation sites is presently less than 1 percent of the total investment in distribution facilities. However, land costs are increasing rapidly in almost all areas, and especially in those areas which are undergoing urban development, or have already been developed. Furthermore, high land costs indirectly affect investment in the substation facilities that are built on the sites. For example, it is common practice in metropolitan business areas where land costs are highest to install indoor substation facilities in multi-story buildings. This reduces the size of the site and the cost of the land, but increases the cost of the substation built on the site. In order to further reduce space requirements, miniaturized substation components with pressurized gas insulation for high voltage buses have recently been developed. This development promises to reduce both site and building sizes and costs, but at the expense of higher equipment cost.

In addition to higher land prices, utilities are encountering more frequent resistance from both property owners and public planning authorities to the construction of substations in the optimum locations. Such resistance also increases costs, in some cases because a less economical location must be used, and in others because of long delays in getting needed facilities built.

Appearance of Facilities

In order to improve the appearance of distribution facilities, utilities are making various changes in their practices. Among those that add significantly to substation costs are ornamental fences or enclosures for the stations and landscaping of the

sites. Line costs are increased by the painting and staining of wood poles, use of metal and concrete poles, the use of underground construction for new lines (extensions), and the replacement of existing overhead lines with underground (conversions). This trend to higher appearance standards has been a factor tending to increase costs during the past 15 years, and is expected to exert a greater influence in this respect in the future. The trend to underground distribution in particular is becoming a major cost factor and is considered in detail in the following section.

SECTION 2—EFFECT OF TREND TO UNDERGROUND ON COSTS

The use of underground for distribution lines is increasing rapidly. The anticipated effect of this trend upon costs is considered in this section. For convenience in this discussion, the term "extension" is used to designate any new distribution line, and the term "conversion" to designate the replacement of an existing overhead with an underground line.

Underground Extensions

The use of underground construction for extensions to serve new residential and commercial developments is rapidly becoming normal practice. The impact of this trend on the future cost of energy depends upon a number of factors which are discussed below.

Relative Investment Costs

The impact of the trend to underground extensions upon future energy costs will depend largely upon the relative costs of underground and overhead distribution lines. Determination of these relative costs is especially difficult because the area of concern is with the types of lines that historically have been constructed overhead, but will be underground to an increasing extent in the future. These are not the types of lines that were generally built underground in the past, and past experience furnishes very little of the needed cost information. The techniques and costs of placing the types of lines involved underground have been changing rapidly and will continue to do so for some years.

This last point is important because the impact of this increased use of underground upon future energy costs will be determined largely by future rather than present relative costs of underground and overhead. Future relative costs, in turn, will be determined largely by the success of research and development efforts to reduce underground costs.

A further difficulty is that relative costs vary widely with the type of distribution involved. Underground-to-overhead investment cost ratios in new residential areas (URD type lines) are now on the order of 2 to 1. Ratios for commercial and industrial distribution and for main feeder lines, which involve mostly 3-phase circuits, larger conductors, and more costly switching facilities, are much higher and are expected to remain higher. Underground has been considered economically impracticable for rural lines, but recent developments using cable-plowing techniques indicate that under favorable conditions some rural lines can be placed underground at costs comparable to overhead. The composite ratio for all types of lines is a function of the relative amounts of these different types of lines that are being placed underground as well as of the cost ratio for each type.

There is also considerable difference among the current cost ratios quoted by different utilities for the same types of lines. These reflect differences in conditions, techniques, and methods of computing the cost ratios.

Because of these uncertainties and variables, any estimates of present and, especially, of future average ratios of underground to overhead cost must be somewhat speculative and based largely upon judgment. Table III–c shows the Distribution Technical Advisory Committee's estimates of the average present ratios of new line extensions and probable future ranges of these ratios.

The ratios in Table III–c are estimated average ratios of underground investment to the investment required for equivalent overhead lines. It is expected that the ratios will continue to decrease until about 1980 as a result of technological advances in underground, and then will level off. Because of the uncertainty of predicting the extent to which present costs can be reduced, ratios for the 1980–90 period are expressed as probable ranges.

TABLE III-c

Average Ratios of Underground to Overhead Cost for Extensions

	1967	Probable range 1980–90 Maximum	Minimum
URD type lines (note 1)	1.8	1.5	1.3
Other types of lines (note 2)	5.0	4.0	3.3
All lines—Weighted average (note 3)	2.9	2.7	2.3

Notes: 1. URD type lines are branch lines serving new residential subdivisions, predominantly single phase and with relatively small primary conductors.

2. Other types of lines include distribution in new commercial and industrial developments, and rural areas, and main primary circuits of large conductor through residential and other areas.

3. These two types of lines are weighted on the basis of the relative amounts (measured in dollars of cost to build them overhead) that are expected to be built underground. The 1967 weighting is ⅔ URD and ⅓ other types; the 1980–90 weighting is 50 percent of each type.

Relative Operation and Maintenance Costs

Operating experience has been extremely limited with the new types of underground systems being built in lieu of overhead, and the evolution of these new systems is still very incomplete. Therefore, it is not possible to make any meaningful quantitative comparisons of future operation and maintenance expense between such systems and equivalent overhead systems. Some of the expenses of operating and maintaining overhead systems (such as tree trimming, repairing damage and restoring service after vehicle collisions, snow, ice, wind and lightning storms, etc.) are matters of common knowledge. Persons unfamiliar with the problems of operating and maintaining underground systems tend to assume that, because these obvious overhead expenses are avoided, total operation and maintenance expenses will be lower for underground than for overhead. On the contrary, such studies as have been made, based on experience with conventional underground systems, generally indicate that expenses are higher for underground than for overhead. Whether this will be true for the new types of underground systems now being substituted for overhead remains to be seen. On the basis of available evidence, it appears that the expense of operating and maintaining these systems will probably be higher than for equivalent overhead systems, and this factor is recognized in Section 3 of this part of the report.

Trend to Increased Use of Underground

The trend to substitute underground for overhead in extensions to supply new subdivisions is described in Part I, Section 3. This trend is expected to continue, encouraged by Governments at all levels and facilitated by declining underground-to-overhead cost ratios for extensions. Underground installation of extensions in new residential subdivisions and new commercial developments is becoming general practice. Increased use of underground distribution in other types of extensions, including industrial parks, rural lines, and main primary feeders is also expected.

In summary, the Distribution Technical Advisory Committee estimates that about 20 percent of all the extensions built in 1968 of the types that would have been built overhead under former practices (measured in dollars that it would have cost to build them overhead) were actually built underground; and that this percent will increase to 70 percent by 1975 and 90 percent by 1990.

Effect on Distribution Investment

Table III–d shows the calculated ranges of effects that this expected trend to underground extensions will have on distribution investment in 1980 and 1990, based upon the cost ratios of Table III–c.

Effect on Cost of Energy

The effect of this added investment for underground extensions upon the cost of energy in 1980 and 1990 will depend largely upon the extent to which the utilities recover it through contributions in aid of construction. Such contributions reduce the estimated average annual fixed charged on investment by eliminating the components of return on invested capital and taxes on income. In this report, an average fixed charge rate of 4 percent is used for the portion of the added investment covered by contributions.

The investment costs shown in Table III–d include both the original costs of extensions and subsequent increases in the investment cost of these lines resulting from additions and replace-

TABLE III–d

Effect of Increased Undergrounding of Extensions on Investment

	Millions of dollars			
	1980		1990	
	Maximum	Minimum	Maximum	Minimum
Added undergound investment	$16,000	$14,500	$52,200	$44,600
Less overhead investment avoided	6,200	6,200	19,300	19,300
Net increase in investment	9,800	8,300	32,900	25,300

ment of components. Assuming that it is practicable to recover only the difference in original cost through contributions, Table III–e shows the impact of increased undergrounding of extensions on annual fixed charges in 1980 and 1990 for 0 percent, 50 percent and 100 percent of the difference in original cost contributed. Fixed charges per customer and per kWh are shown, based on all customers served by utilities and all energy sold to them whether or not they are supplied through distribution systems.

In addition to the increases in fixed charges shown in this table, increased undergrounding of extensions will probably result in higher operation and maintenance expenses.

TABLE III–e

Effect of Increased Use of Underground Extensions on Fixed Charges

	Increase in annual fixed charges			
	1980		1990	
	Maximum	Minimum	Maximum	Minimum
Per customer:				
No contributions	$17.20	$13.30	$44.60	$34.40
50 percent contributions	11.80	9.00	31.80	24.40
100 percent contributions	6.50	4.80	18.90	14.50
Cents per kWh sold:				
No contributions	0.051	0.039	0.083	0.064
50 percent contributions	.035	.027	.059	.046
100 percent contributions	.019	.014	.035	.027

Potential Effects of Expanded Conversion Programs

The accelerated trend to the use of underground for new line extensions will have the effect of greatly reducing the historical rate of increase in the total mileage of overhead lines. However, unless the past rate of conversions from overhead to underground is also increased, the total mileage of overhead will continue to increase gradually through the 1967–90 period. The total investment in overhead lines will be increasing at a much more rapid rate than the mileage because of additions and replacements of components in existing lines. It is calculated that this overhead investment will increase from 18.5 billion dollars in 1967 to 30.2 billion in 1980 and 40.0 billion in 1990.

Relative Investment Costs for Conversions

The future extent of overhead lines can be reduced by increasing the rate of expenditures for converting existing overhead lines to underground. Estimating average cost ratios for such conversions is subject to the same difficulties and uncertainties as for new line extensions. In general, the ratios are much higher than for extensions because of the less favorable construction conditions of conversions, and also because, for convenience in the computations of this report, they are expressed as ratios of new underground cost to the original cost of the lines converted rather than to the cost to build equivalent new overhead lines. Assuming an average age of 15 years for the existing overhead lines, with construction costs increasing at about 2.4 percent per year, the original cost of these lines would be about 70 percent of the cost to build equivalent new lines. Therefore, the ratios to original cost used in this report are about 40

TABLE III–f

Average Ratios of New Underground to Original Overhead Cost for Conversions

	1967	1980–90 Maximum	1980–90 Minimum
URD type lines	7.0	5.6	4.7
Other types of lines	10.0	8.0	6.7
Weighted averages:			
Selective programs	9.7	7.8	6.5
General programs	9.7	6.8	5.7

percent higher than if the ratios were based on the cost of new overhead lines.

Table III–f shows the Distribution Technical Advisory Committee's estimates of the average present and future cost ratios for conversions. Different future average ratios are indicated for "selective" and for "general" conversion programs. Selective programs would be largely concentrated in commercial and civic areas, whereas general programs would involve an increasing percentage of less costly residential area conversions and lower overall average costs in the future.

Cost to Eliminate Existing Overhead Distribution

There have been various proposals that the rate of converting existing overhead lines to underground be increased sufficiently to eliminate all overhead in the foreseeable future. In order to estimate the cost of approaching such a goal, it was assumed that during the years 1971–90, the past rate of conversion expenditures would be increased by some uniform amount per kWh sold in each year, sufficient to reduce the 1990 overhead investment to about 6 billion dollars. This remaining overhead investment is 10 percent of the total extrapolated overhead investment (before adjustment for the effects of increased undergrounding of extensions) and corresponds to the forecast that 10 percent of the new line extensions will still be built overhead in 1990.

The estimated effects upon 1990 investment in distribution lines are shown in Table III–g.

The increase in total investment would be 171 billion dollars at maximum underground costs or 143 billion at minimum costs. However, since the 28 billion dollar investment in the existing lines cannot be recovered by removing them, the total investment capital required for the program (including the increased cost of subsequent betterments) is 199 billion dollars at maximum costs or 171 billion at minimum costs. This amounts to between $1,720 and $2,000 per customer for every customer that will be receiving electric utility service in 1990. It is 3 ½ to 4 times as much as the total 1967 investment in *all* distribution facilities of $497 per customer (Table III–a) and is on the order of 1 ½ times the extrapolated total distribution investment of $1,250 per customer in 1990 (Table III–b).

Fixed charges on distribution investment are one of the major components in the total cost of energy. An increase in distribution investment of this order of magnitude would have an extremely adverse impact upon the cost and the growth in use of electrical energy, unless most of it were offset by contributions in aid of construction. Contributed capital on this scale, on the order of 150 to 200 billion dollars, is not expected to be available.

TABLE III–g

Effects of General Conversion Program on 1990 Line Investment

	Millions of dollars: Maximum costs	Millions of dollars: Minimum costs
Increase in underground investment:		
Conversion expenditures	$188,000	$162,000
Subsequent betterments (note 1)	17,000	15,000
Total increase	205,000	177,000
Decrease in overhead investment:		
Existing lines removed	28,000	28,000
Subsequent betterments avoided (note 1)	6,000	6,000
Total decrease	34,000	34,000
Increase in total investment	171,000	143,000
Total investment capital required	199,000	171,000

Note 1: Subsequent betterments are increases in investment in the lines resulting from additions and replacements of components subsequent to the dates when they would be converted under the program.

Selective Conversion Programs

The visual impact of existing distribution lines can be significantly reduced by conversion programs of more limited scale than this, by selecting for conversion those lines that have a particularly adverse impact. Overhead lines vary greatly in, this respect, depending upon their location, design, and condition. Lines located in business, civic and public recreation areas and along heavily traveled thoroughfares have an especially adverse impact because they are seen daily by many people. Lines in residential areas have less impact and those in rural areas still less. The impact is reduced where the lines are partly screened from public view by trees, buildings, or other obstacles. It is increased if the lines are in poor condition or unusually congested with wires and equipment.

TABLE III–h

Effects of Selective Conversion Program on 1990 Costs

	Millions of dollars	
	Maximum costs	Minimum costs
Increase in underground investment:		
Conversion expenditures..	$18,600	$18,600
Subsequent betterments...	1,800	1,800
Total increase.........	20,400	20,400
Decrease in overhead investment:		
Existing lines removed....	2,400	2,800
Subsequent betterments avoided	500	600
Total decrease.........	2,900	3,400
Increase in total investment...	17,500	17,000
Total investment capital required............	19,900	19,800
Increase in 1990 fixed charges (Cents per kWh)	0.047	0.047

Table III–h illustrates what might be achieved by an industry-wide selective conversion program and the costs involved. It is based on an annual capital expenditure for conversions equivalent to .03 cents per kWh sold for the 20-year period 1971–90 inclusive, with no contributions. The "selective" conversion cost ratios of Table III–e were used.

The projected investment in overhead lines, after adjustment for the effect of increased undergrounding of extensions, is 40 billion dollars (Table B–c, Appendix B). The conversion program described by Table III–h would require total investment capital of about 20 billion dollars and would eliminate about 8 percent of the projected overhead investment of 40 billion dollars. By selective conversion of the lines with the greatest visual impact, the aesthetic improvement would be very substantial.

The increase in 1990 fixed charges in Table III–h consists of fixed charges on the net increase in total investment, plus the estimated annual cost to retire prematurely the existing overhead lines, assuming that their average age at time of conversion is 15 years and their normal life expectancy is 30 years. The increase in fixed charges per dollar expended for conversions would be less than indicated by the Table to the extent that conversions could be scheduled to coincide with the need to replace or rebuild overhead lines for other reasons, such as deterioration, need to increase capacity, or need to relocate because of street widening or other improvements. For a conversion so scheduled, the cost to build a new overhead line rather than the investment in the existing line should be deducted in computing the net increase in investment; and the conversion program should not be charged with the cost of prematurely retiring the existing line.

In addition to the increase in fixed charges, a conversion program such as described in Table III–h would probably result in some increase in operation and maintenance expense.

Table III–h is illustrative only. The annual expenditure of .03 cents per kWh for conversions might be greater or smaller, and both the results and the costs of the conversion program would vary in proportion. Contributions from governments and/or property owners requesting or benefiting from such selective conversions could be used to offset some of the investment cost and thus reduce the impact upon the cost of energy, or to increase the amount of funds available for conversions without increasing this impact.

TABLE III–i

Computation of Probable Future Cost Ranges

[Assuming no increase in rate of conversions]

	Cents per kWh sold to all customers			
	1980		1990	
	Maximum	Minimum	Maximum	Minimum
1967 cost level (from table III–b)	0.523	0.523	0.523	0.523
Future levels by extrapolation (table III–b)	.431	.431	.375	.375
Decrease indicated by extrapolation	−.092	−.092	−.148	−.148
Future levels by extrapolation	.431	.431	.375	.375
Add for: (see note 1–a, b, c):				
(a) Decreasing rate of cost reduction	.046	.023	.074	.037
(b) Fixed charges on underground extensions	.051	.014	.083	.027
(c) O&M expense on underground extensions	.008	.000	.012	.000
Total (note 2)	.536	.468	.544	.439
Reduce cost range ⅓ (note 2)	−.011	+.012	−.017	+.018
Probable future cost range	.525	.480	.527	.457
1967 cost level	.523	.523	.523	.523
Change from 1967 level	+.002	−.043	+.004	−.066

Notes: 1. It is improbable that the average cost level will actually decrease in the future to the extent indicated by extrapolation (Table III–b) for various reasons given in Sections 1 and 2 of this part of the report. Therefore, the future costs indicated by extrapolation have been increased by adding to them the maximum and minimum probable effects of the following three factors:

(a) In Section 1 it is concluded that the factors that have tended to influence costs in the downward direction in the past will probably be less effective in this respect in the future. Therefore, the extrapolated future cost levels have been increased by a maximum of 50 percent and a minimum of 25 percent of the decreases from the 1967 level that were indicated by extrapolation.

(b) Table III–e in Section 2 shows the estimated effects of increased undergrounding of extensions upon future fixed charges. These effects will depend largely upon the extent to which utilities recover the additional investment costs of underground extensions through contributions in aid of construction, and, therefore, there is a wide variation between the maximum and minimum effects which have been added to the extrapolated future costs in Table III–i.

(c) It was indicated in Section 2 that no meaningful estimates could be made of the relative operation and maintenance expense of overhead and underground lines because of lack of data, but that expenses would probably be higher for underground. For the purpose of Table III–i, it was assumed that the trend to underground extensions would increase the extrapolated total distribution operation and maintenance expenses by 0 to 10 percent in 1980, and by 0 to 20 percent in 1990. These figures represent an increase of 0 to 0.008 cents per kWh in 1980 and 0 to 0.012 cents per kWh in 1990.

2. If all three of these factors were to have their maximum probable effects upon future costs, the computed 1980 cost level would be .536 cents and the 1990 level .544 cents per kWh. Similarly, if all three were to have their minimum probable effects, the 1980 level would be .468 cents and the 1990 level .439 cents. However, because these extreme combinations of effects are improbable, the maximum figures thus obtained have been reduced and the minimum figures increased by ⅙ of the spread between the minimum and the maximum, thus reducing the probable ranges of future costs by ⅓.

SECTION 3—PROBABLE FUTURE COST LEVELS

Because there are many uncertainties involved in long range forecasting of future cost levels, it would be imprudent to attempt to do more than estimate the probable ranges within which future costs will fall. Even this approach requires assumptions regarding certain factors that will have a significant influence upon future costs.

Basis of Forecast

In the following forecast it is assumed that:

1. The average fixed charge rate will remain at approximately the present level of 13.5 percent.
2. Prices of distribution materials and labor will continue to increase at an average annual rate of about 2.4 percent.
3. There will be no substantial increase in the historical rate of expenditures for converting overhead lines to underground.

Forecasting changes in fixed charge rates and in the rate of price inflation is considered outside the scope of this report. It would be speculative to attempt to forecast the extent of future conversion programs or their impact upon the cost of distribution, because there is at present no clear indication of what the order of magnitude of future expenditures for conversions will be nor to what extent contributions will be used to provide funds for them.

Forecast of Future Cost Ranges for Assumed Conditions

Probable ranges of distribution costs in 1980 and 1990 per kWh sold to all ultimate customers, for the above assumed conditions, are developed in Table III–i.

The probable future cost ranges thus computed are .525 to .480 cents in 1980 and .527 to .457 cents per kWh in 1990. At the maximum they represent increases over the 1967 level of a fraction of one percent; at the minimum they represent decreases of about 8 percent by 1980 and 12½ percent by 1990.

The kWh base used in Table III–i is the estimated total energy that will be sold to all ultimate customers of utilities in 1990. Assuming that 25 percent of this energy will be used by large customers not served through distribution systems, Table III–j summarizes the probable future cost levels per kWh delivered through distribution systems.

Potential Effects of Increased Rates of Conversion

Tables III–i and III–j indicate that, for the assumed conditions, the cost of distribution per kWh will probably continue to decline, but at a more moderate rate than in the past 15 years. The most important of these assumed conditions is that there will be no substantial increase in the historical rate of expenditures of conversions. It is probable that there will be some increase in this rate, although there is at present no basis for forecasting the magnitude of future conversion expenditures.

The possible effects of expanded conversion programs are illustrated in Section 2 of this part of the report by analyzing two hypothetical programs. The smaller "selective" program summarized in Table III–h would increase fixed charges in 1990 by about .047 cents per kWh sold to all customers or .063 cents per kWh sold to distribution customers. This is less than the maximum probable decrease from the 1967 level inindicated by Tables III–i and III–j, and might be possible without causing the overall cost of distribution per kWh to increase.

The larger "general" program summarized in Table III–g would require capital funds on the order of 150 to 200 billion dollars. Even if funds on this scale could be made available, such a conversion program would more than double the total 1990 investment in all distribution facilities. The 1990 cost of distribution per kWh would be considerably higher than the 1967 level.

TABLE III-j

Probable Future Cost Ranges per Distribution KWH

[Assuming no increase in rate of conversions]

	Cents per kWh sold to distribution customers	
	Maximum	Minimum
1967 level	0.697	0.697
1980 range	.700	.640
1990 range	.703	.609
Change: 1967–80	+.003	−.057
Change: 1967–90	+.006	−.088

APPENDIX A

DISTRIBUTION SYSTEM LOADS

The purpose of this appendix is to present in greater detail the data upon which the material in Part I, Section 1 is based. Of principal concern are the energy-use and demand characteristics of the distribution customer, both today and as projected to the year 1990. It is evident that any projection of loads and demands over a twenty-year period can serve only as a general guide reflecting the best judgment of the electric utility industry at this time.

National Statistics

The information in this section consists of national averages for the contiguous United States (excluding Alaska and Hawaii). The tables are largely self-explanatory, but the comments following the tables should be helpful in interpreting them.

More than 99 percent of the customers are in the three categories of non-farm residential, farm (excluding drainage and irrigation pumping), and commercial. From 1970 to 1990, the number of non-farm residential customers is expected to increase about 47 percent and commercial customers 34 percent, while farm customers decrease 12 percent.

The first three classes of customers, constituting more than 99 percent of the total number of customers, use about 50 percent of the energy sold. The industrial customers, who are relatively few in number, use most of the remainder. From 1970 to 1990, the energy sold to non-farm residential customers is expected to increase 271 percent, to farm customers 162 percent, and to commercial customers 309 percent. The principal function of distribution systems is to distribute energy to these three types of customers. The growth in energy sales to farm customers is only about 3 percent of the total growth in these three customer classes, indicating that most of the growth on distribution systems will be in the other two categories.

TABLE A–a

Numbers of Ultimate Customers by Classes-Contiguous USA

Class of customer	Thousands of customers				Percent of total			
	1965 Actual	1970	1980	1990	1965	1970	1980	1990
Nonfarm Resident	53,317	58,134	70,985	85,341	82.4	83.4	84.9	85.9
Farm	3,789	3,429	3,171	3,003	5.9	4.9	3.8	3.0
Subtotal	57,106	61,563	74,156	88,344	88.3	88.3	88.7	88.9
Commercial	7,057	7,629	8,819	10,193	10.9	10.9	10.5	10.3
Subtotal	64,263	69,192	82,975	98,537	99.2	99.2	99.2	99.2
Industrial and Miscellaneous	512	552	660	786	0.8	0.8	0.8	0.8
Total	64,775	69,744	83,635	99,323	100.0	100.0	100.0	100.0

Source: Regional Advisory Committee Forecasts; except numbers of industrial and miscellaneous customers were estimated from percentage of such customers in FPC Statistics of Investor-Owned Utilities in the United States—1967.

TABLE A–b

Energy Sales by Customer Classes-Contiguous USA

Class of customer	Billion kilowatt-hours				Percent of total			
	1965 (Actual)	1970	1980	1990	1965	1970	1980	1990
Nonfarm Resident	254	380	755	1,409	26.4	27.3	26.9	26.4
Farm	27	37	60	97	2.8	2.7	2.1	1.8
Subtotal	281	417	815	1,506	29.2	30.0	29.0	28.2
Commercial	190	278	577	1,138	19.7	20.0	20.6	21.4
Subtotal	471	695	1,392	2,644	48.9	50.0	49.6	49.6
Industrial	436	614	1,257	2,386	45.3	44.1	44.7	44.9
Irrigation and drain pumping	11	15	23	34	1.1	1.1	0.8	0.6
Street and highway lighting	9	12	22	39	0.9	0.9	0.8	0.7
Electric transport	5	5	7	8	0.5	0.4	0.3	0.2
All other	32	48	106	215	3.3	3.5	3.8	4.0
Total	964	1,389	2,807	5,326	100.0	100.0	100.0	100.0

Source: Regional Advisory Committee Forecasts.

TABLE A–c

Energy Sales per Customer by Regions, Nonfarm Residential and Commercial Customers

Class of customer and region	Annual kWh per customer			
	1965 (Actual)	1970	1980	1990
Nonfarm, Residential:				
Northeast	3,646	4,815	7,920	12,701
Southeast	6,763	9,415	14,114	17,058
East Central	4,413	5,714	9,130	14,913
West Central	4,253	6,093	10,500	17,279
South Central	4,953	7,260	13,880	23,580
West	5,363	6,870	10,870	17,197
Total USA (contiguous)	4,766	6,529	10,636	16,505
Commercial				
Northeast	24,148	32,689	57,840	100,165
Southeast	27,405	40,171	88,676	187,349
East Central	25,734	34,583	60,117	100,021
West Central	23,381	33,023	58,464	98,947
South Central	27,959	37,480	59,530	84,440
West	33,566	42,408	68,646	106,617
Total USA (contiguous)	26,962	36,468	65,370	111,675

Source: Regional Advisory Committee Forecasts.

FIGURE A–1

Therefore, the remainder of this appendix is concerned with energy use and kW demands of non-farm residential and commercial customers.

Energy Use by National Power Survey Regions

The energy use data in this section are by National Power Survey regions which are shown in Figure A–1.

Energy sales for nonfarm residential and commercial customers are shown in Table A–c.

The substantial differences among the six regions in kWh sales per residential customer reflect differences in climate, density of the residential developments, and relative costs of electricity and competing forms of energy. The Distribution Technical Advisory Committee questionnaire circulated to representative utilities in each regional area, which obtained projected kWh usage per new dwelling unit, indicated closer similarity between regions than Table A–c.

If the trend toward total electric convenience and living is national rather than regional, it would tend to increase the forecast usage in the high population density regions. Therefore, national rather than regional data has been used throughout this report, thus avoiding this situation of concern. From 1970 to 1990, national average consumption per customer is expected to increase 153 percent for residential and 206 percent for commercial customers.

kWh Use and kW Demands for New Residential Customers

To supplement the data received from other sources, the Distribution Technical Advisory Committee sent out questionnaires to investor-owned and publicly-owned utilities throughout the United States. Information received is summarized in Table A–d, A–e, and A–f.

Table A–d shows estimated average energy use for new residential customers being added to the distribution system in the indicated years. The data is classified by single-family and multifamily dwelling units and by small, medium, and large energy-use customers. This information is plotted on Figure I–1 in Part I, Section 2.

The distinction between single-family and multifamily dwelling units is clear-cut. A single-family unit is a complete building housing one family. A multifamily unit is the living quarters of one family in a building that houses several such families.

The distinction between small, medium, and large residential customers is less clear-cut, but is intended to indicate the extent to which electricity rather than some other form of energy is used to supply household energy needs. A small energy-use customer uses electricity for lights and small appliances and in some cases has one or two major electrical appliances such as a range, dryer, water heater or air conditioner. A medium energy-use customer has several major electrical ap-

TABLE A–d

Energy Sales per New Residential Customer, Single-Family and Multifamily Customers

Class of customer	Annual kWh per new customer[1] 1965 (Actual)	1970	1980	1990
Single-family residential:				
Small-use	3,900	5,000	7,200	10,200
Medium-use	7,000	8,900	13,200	19,000
Large-use	16,500	19,900	26,600	35,300
Multifamily residential:				
Small-use	3,000	3,700	5,100	7,100
Medium-use	5,000	6,000	8,100	11,600
Large-use	9,700	11,800	15,400	20,400

[1] Contiguous USA.

Source: Distribution Advisory Committee Questionnaire.

TABLE A–e

Energy Sales per New Residential Customer By Regions, Single-Family and Multifamily Customers

Region	Annual kWh per customer: Small-use customer 1965	1970	1980	1990	Medium-use customer 1965	1970	1980	1990	Large-use customer 1965	1970	1980	1990
Single-family residential:												
Northeast	3,300	4,600	6,400	8,900	6,300	8,700	12,800	17,800	19,600	24,100	30,600	37,800
Southeast	3,800	5,300	8,700	12,900	6,900	8,900	14,800	20,100	21,600	27,000	37,100	47,900
East Central	4,400	5,600	8,700	13,600	7,000	8,800	14,000	22,400	12,800	16,000	22,400	30,400
West Central	3,800	4,700	6,100	7,600	5,400	6,800	9,300	12,300	10,500	12,400	16,700	23,000
South Central	4,600	5,400	7,300	10,300	9,500	11,200	15,500	21,400	15,400	18,700	25,500	34,200
West	4,000	4,800	6,700	9,600	7,100	8,700	13,100	19,700	19,800	22,800	30,200	40,600
Total USA (contiguous)	3,900	5,000	7,200	10,200	7,000	8,900	13,200	19,000	16,500	19,900	26,600	35,300
Multifamily residential:												
Northeast	2,000	2,600	4,100	5,700	3,500	4,700	7,200	9,800	11,600	13,900	18,700	24,100
Southeast	4,600	5,400	7,500	10,200	8,300	9,600	13,500	17,900	14,500	17,500	22,200	28,000
East Central	3,200	4,100	5,900	8,300	4,400	5,300	5,200	11,000	7,600	9,200	12,600	17,800
West Central	2,700	3,400	4,500	5,700	3,900	4,800	6,300	7,900	6,300	7,700	9,300	11,800
South Central	3,900	4,600	6,000	8,300	7,300	8,500	11,200	15,000	12,500	15,500	19,900	26,300
West	2,100	2,600	3,400	5,600	2,900	3,600	5,300	8,000	6,500	7,800	11,000	15,200
Total USA (contiguous)	3,000	3,700	5,100	7,100	5,000	6,000	8,100	11,600	9,700	11,800	15,400	20,400

Source: Distribution Advisory Committee Questionnaire.

TABLE A–f

Forecast of Growth in Noncoincident Demand, New Single-Family and Multifamily Residential Customers

Class of customer	Noncoincident demand in percent of 1970[1] 1965 (Actual)	1970[2]	1980	1990
Single-family residential:				
Small-use	84	100	141	203
Medium-use	86	100	138	195
Large-use	86	100	125	157
Multifamily residential:				
Small-use	80	100	140	190
Medium-use	82	100	133	185
Large-use	86	100	129	164

[1] Contiguous USA.
[2] Base year.
Source: Distribution Advisory Committee Questionnaire.

pliances, but uses some other form of energy for space heating and in some cases, for other purposes. A large energy-use customer is one who uses electricity for all of his energy requirements, including space heating.

Table A–e shows the breakdown by regions of the data summarized in Table A–d. The sampling was not in sufficient depth to provide meaningful conclusions, but does indicate that the pattern for kWh use for the new customers differs considerably from forecasts for the composite of new and existing customer use.

The figures in Tables A–d and A–e are not directly comparable to those of Table A–c, since these tables apply to new customers added in the indicated years, whereas Table A–c applies to all customers existing in those years. Energy use will average higher for new than for existing customers in a particular year. However, the predicted rate of growth in energy use is lower for new than for existing customers. Thus, the initial difference in energy use will tend to become smaller in the future.

Tabulated in Table A–f above are the estimated noncoincident demands for single-family and multifamily residential customers. The base year selected is 1970. From 1970 to 1990, an increase in demand of approximately 100 percent is anticipated for the small-use and medium-use customers of both the single-family and multifamily classifications. The large-use customer demand (of both classifications) will increase approximately 60 percent over the same span of years.

Appliance Saturations

One of the major reasons for the increasing energy use per residential customer that is forecast in Table A–c is the increase in the saturation of appliances utilizing electric energy. This is illustrated by Table A–g.

The differences between 100 percent and the 1968 saturation levels in Table A–g indicate the remaining potential of these appliances to increase average residential energy consumption per customer. A greater potential source of future growth than any of the appliances shown in the table is electric space heating, with a current saturation level of only about 5 percent. It is expected that acceptance and use of new types of electric utilization equipment not yet on the market will contribute to continuing growth in average energy use per customer.

TABLE A–g

Use of Major Electrical Appliances in Homes in the USA

Appliance	Percent of homes (saturation) 1958	1963	1968
Air conditioner	10	19	37
Clothes dryer	14	23	36
Dishwasher	5	9	18
Food waste disposer	8	13	18
Food freezer	19	26	27
Range	32	39	47
Refrigerator	97	99	100
Television	(*)	93	98
Vacuum cleaner	68	78	92
Clothes washer	79	86	94
Water heater	17	23	26

* Not available.
Source: Merchandising Week Magazine, Jan. 29, 1968.

APPENDIX B

DISTRIBUTION COSTS

The past trends, present levels, and probable future levels of distribution costs are considered in Part III. The tables and figures of this appendix present in more detail the data upon which the conclusions of Part III are based.

Because of limitations of the source data, the distribution investment costs shown in Table B–a, are partly estimated. For Class A and B investor-owned utilities, the line transformer and service accounts were prorated between overhead lines and underground lines in proportion to the other investment reported in these components. Data regarding other segments of the industry was less complete, and the costs of the investor-owned utilities were used as a guide in estimating the cost breakdowns of these other segments.

The differences between the subtotals and the estimated U.S. totals are accounted for by Federal Projects, the Power Authority of the State of New York, and a number of small utilities. Because the first two of these sell a relatively large amount of energy to a relatively small number of ultimate customers, their inclusion has the effect of increasing the average kWh sold per customer and decreasing the average distribution investment and distribution operation and maintenance expense per kWh sold.

Table B–a provides the data for Table III–a.

TABLE B–a

Electric Utility Statistics, 1967

	Investor-owned A & B	Municipal	Cooperative	Subtotals	Estimated U.S. total
Millions of units:					
Number of ultimate customers	53.3	6.9	5.4	65.6	67.3
kWh sold to ultimate customers	849,000	114,000	48,000	1,011,000	1,103,000
Total utility investment	$64,950	$8,640	$5,420	$79,010	$84,300
Distribution investment:					
Substations	$4,790	$630	$330	$5,750	$5,890
Overhead lines	13,080	1,690	3,320	18,090	18,510
Underground lines	4,720	600		5,320	5,450
Other components	2,850	370	280	3,500	3,580
Total distribution investment	$25,440	$3,290	$3,930	$32,660	$33,430
Distribution operation and maintenance expense	995	132	102	1,229	1,260
Distribution as percent of total investment	39.3	38.1	73.6	41.4	39.8
Per customer:					
kWh sold	15,900	16,500	8,900	15,400	16,400
Distribution investment	$477	$477	$729	$497	$497
Distribution—O&M expense	$18.70	$19.10	$18.90	$18.70	$18.70
Per kWh sold:					
Distribution investment (cents)	3.00	2.86	8.20	3.23	3.03
Distribution O&M expense (cents)	.117	.116	.212	.122	.114

Sources of data: FPC Statistics of Investor-Owned Electric Utilities, FPC Statistics of Publicly Owned Electric Utilities, and REA Annual Statistical Reports.

Trends of kwh Sales, Distribution Investment and Distribution Expense per Customer

Historical trends of kWh sales, distribution investment, and distribution operation and maintenance expense per ultimate customer were developed for the years 1952–66 in the manner illustrated by Table B–a for the year 1967. Data for municipal and cooperative utilities for the earlier years of this period were less complete than for 1967, and more reliance had to be placed upon private utility data for these years as a guide to the whole industry. (Figure B–1)

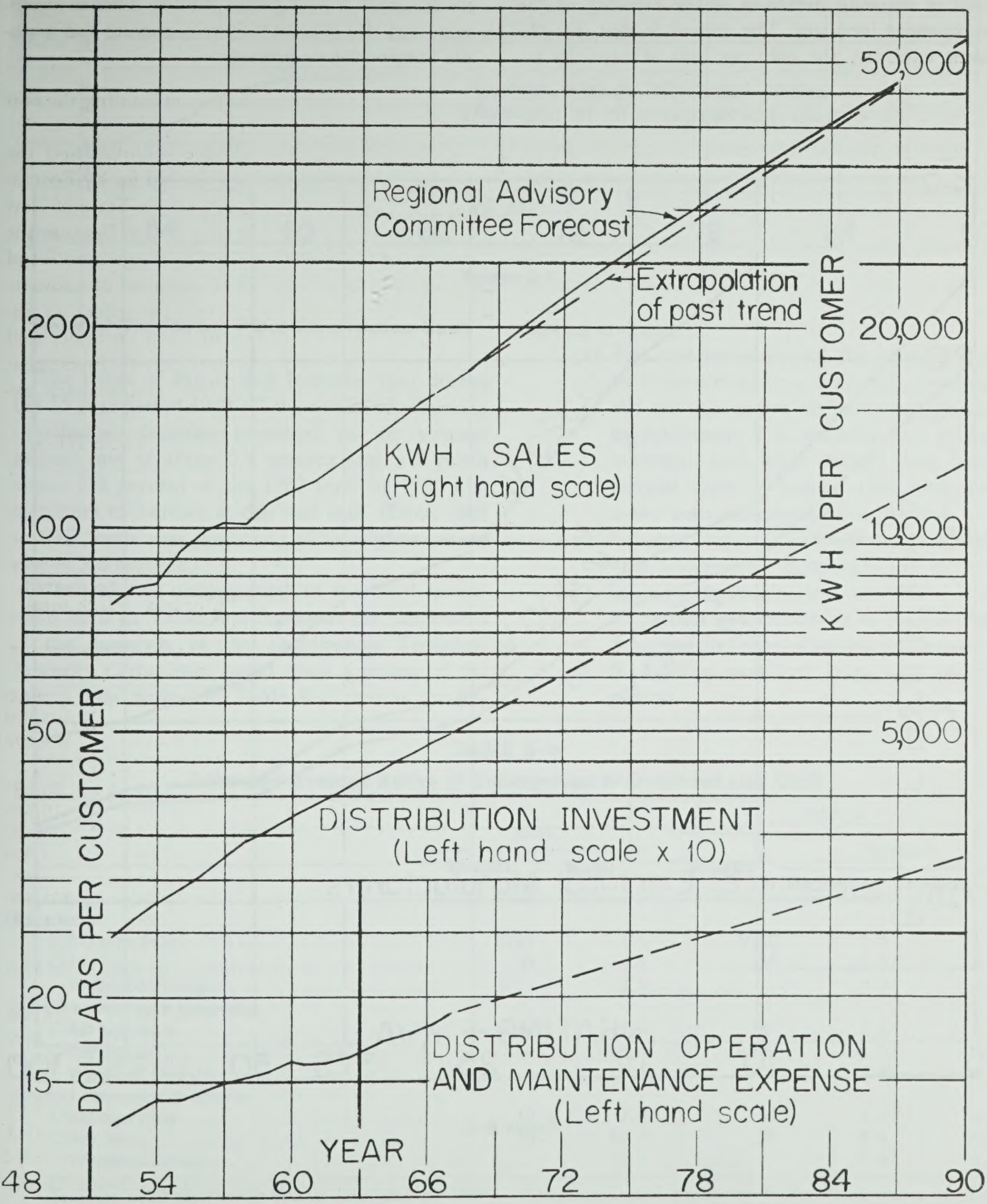


FIGURE B–1.—This Figure Provides the Basis for Table III–b.

Relative Prices of Single-Phase Pole-Type Distribution Transformers

Figure B–2 illustrates certain general relationships between cost, capacity and voltage of distribution system components. One relationship is that, for the same primary voltage, the cost per unit of capacity decreases as the capacity of the component increases. The second is that, for the same capacity, the cost per unit of capacity increases for higher primary voltages. A third relationship is that this added cost per unit of capacity for higher voltage decreases as the capacity of the component increases.

Manufacturer's prices for distribution transformers are used for this illustration. The same relationships between cost, capacity and voltage are generally true of prices of other items of equipment and also of costs to install, operate and maintain distribution equipment.

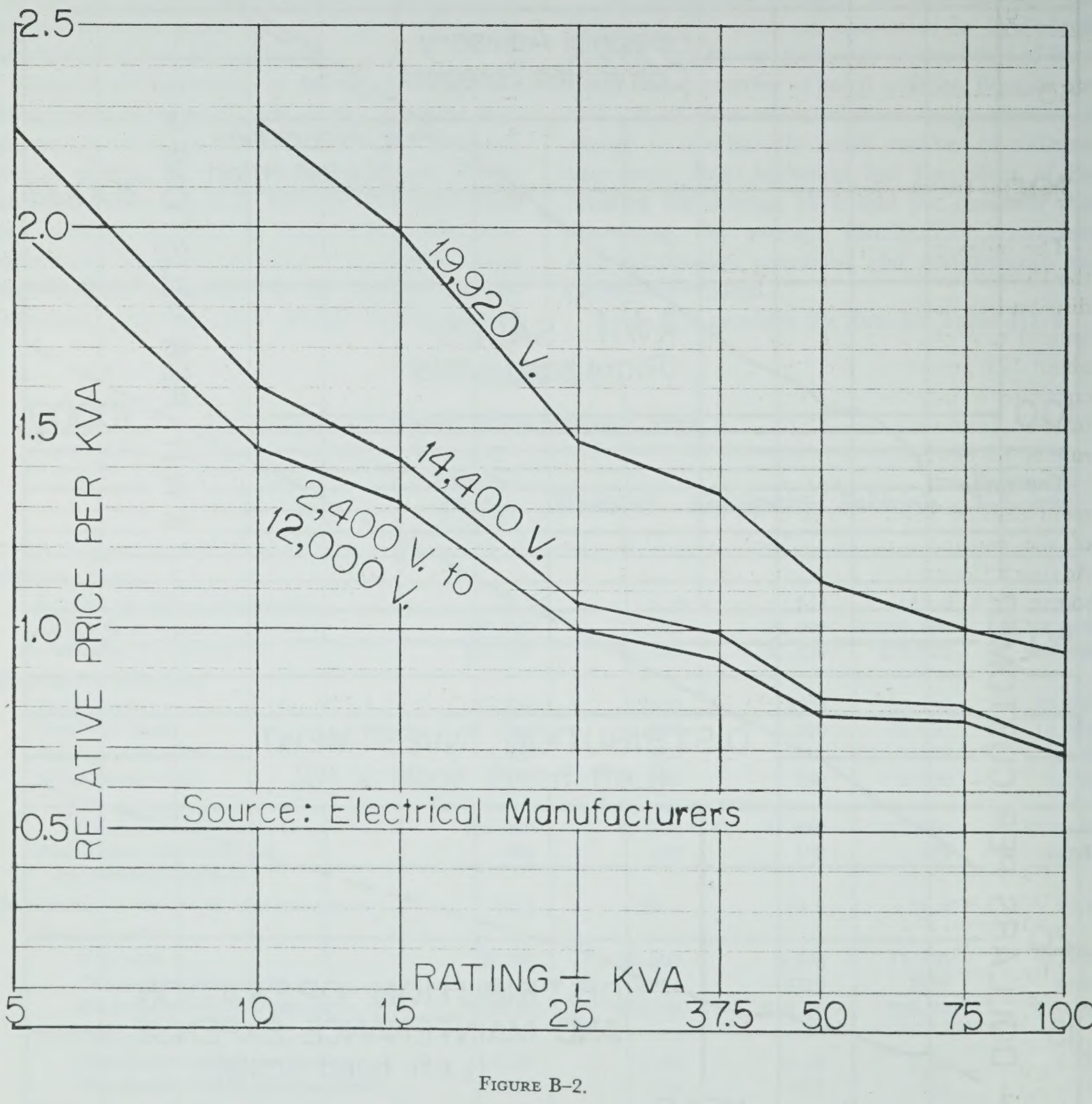


FIGURE B–2.

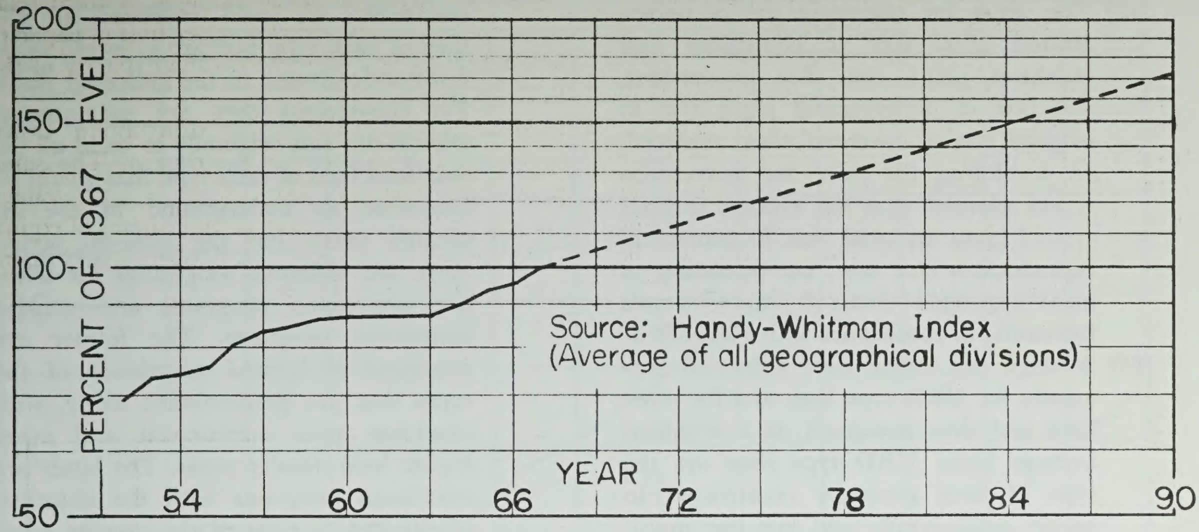


FIGURE B–3.

Trend of Distribution Plant Construction Costs

The index of Figure B-3 indicates that during the 15 year period 1952–67 the cost of constructing distribution facilities increased at an average annual rate of about 2.4 percent and will reach about 172 percent of the 1967 level by 1990 if it continues to increase at this past rate. (From 1963 to 1967, costs were increasing at the higher annual rate of 3.6 percent.)

The ratios of underground to overhead investment costs in Table B–b represent the judgement of the members of the Distribution Technical Advisory Committee, based upon a review of the source data indicated. Table B–b reflects the following concepts:

(1) The cost ratios are for the types of lines that historically have been built overhead but are expected to be built underground in the future. This excludes low voltage networks and other heavy duty commercial types of systems that have normally been underground in the past.

(2) Separate ratios are shown for extensions and conversions. Extensions are defined as new lines usually, but not always, built to connect new customers to the distribution system. Conversions are replacements of existing overhead lines with underground.

TABLE B–b

Estimated Average Ratios of Underground to Overhead Line Costs

	1967		1980–90		
	Weight	Ratio	Weight	Ratio: Maximum	Ratio: Minimum
Extensions					
URD type lines	0.67	1.8	0.50	1.5	1.3
Other lines	.33	5.0	.50	4.0	3.3
Weighted average		2.9		2.7	2.3
Selective conversion programs:					
URD type lines	.10	7.0	.10	5.6	4.7
Other lines	.90	10.0	.90	8.0	6.7
Weighted average		9.7		7.8	6.5
General conversion programs:					
URD type lines	.10	7.0	.50	5.6	4.7
Other lines	.90	10.0	.50	8.0	6.7
Weighted average		9.7		6.8	5.7

Sources: URD Conference Papers submitted for 1969 IEEE Conference on Underground Distribution, Studies by utilities represented on Distribution Technical Advisory Committee, and Study by Utility Task Force on Environment.

(3) The ratios for extensions are of underground plant cost to equivalent new overhead plant cost. For conversions, they are of underground plant cost to original cost of overhead plant replaced. In developing the ratios for conversions it was assumed that the average original cost of plant replaced was 70 percent of reproduction cost new, corresponding to an average age of about 15 years with costs increasing in accordance with Figure B–3.

(4) Average cost ratios were estimated separately for URD type lines and for other lines and then combined on a weighted average basis. URD type lines are the type of lines generally constructed to supply single-family and low rise multifamily residential areas, predominantly single phase with small primary conductors. Other lines include distribution in commercial, industrial and high rise residential areas, predominantly three phase and involving larger primary conductors. They also include main primary feeders of large conductor that supply and extend into and through single-family and low rise residential areas, and rural lines that supply areas of low customer density.

(5) For extensions, the relative weights that are given to these two types of lines are estimates of how much it would cost (relatively) to build overhead all the lines of each type that are expected to be built underground in the indicated years. For conversions they are estimates of what it did cost originally to build all the overhead lines of each type that would be converted to underground in the indicated years. For the 1980–90 period there are different weightings for selective conversion programs and general conversion programs. The former are programs of limited magnitude of the types that are predominant today, with emphasis upon commercial and other higher load density areas. The latter are maximum programs with the objective of eliminating most of the existing overhead lines in all types of areas.

(6) Because of the greater uncertainty involved in predicting future costs, maximum and minimum ratios were developed for the 1980–90 period. The actual levels of these future costs will be determined by the results of current and future research and development efforts to develop lower cost underground systems.

Future Trends of Underground/Overhead Investment Cost Ratios

The curves of Figure B–4 show the assumed year-by-year reductions in the underground to

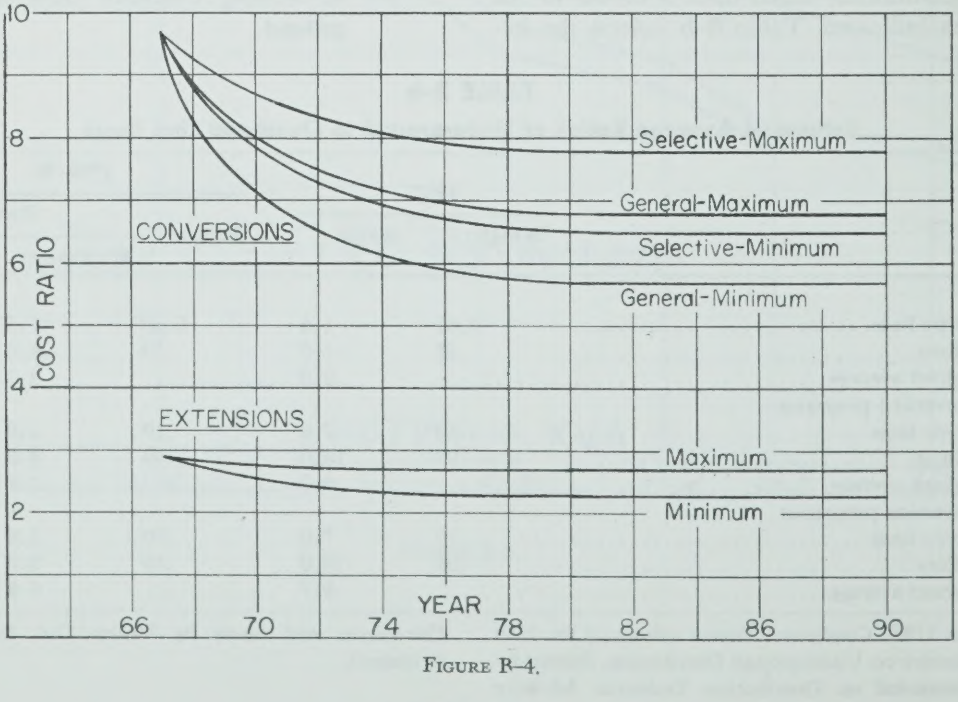


FIGURE B–4.

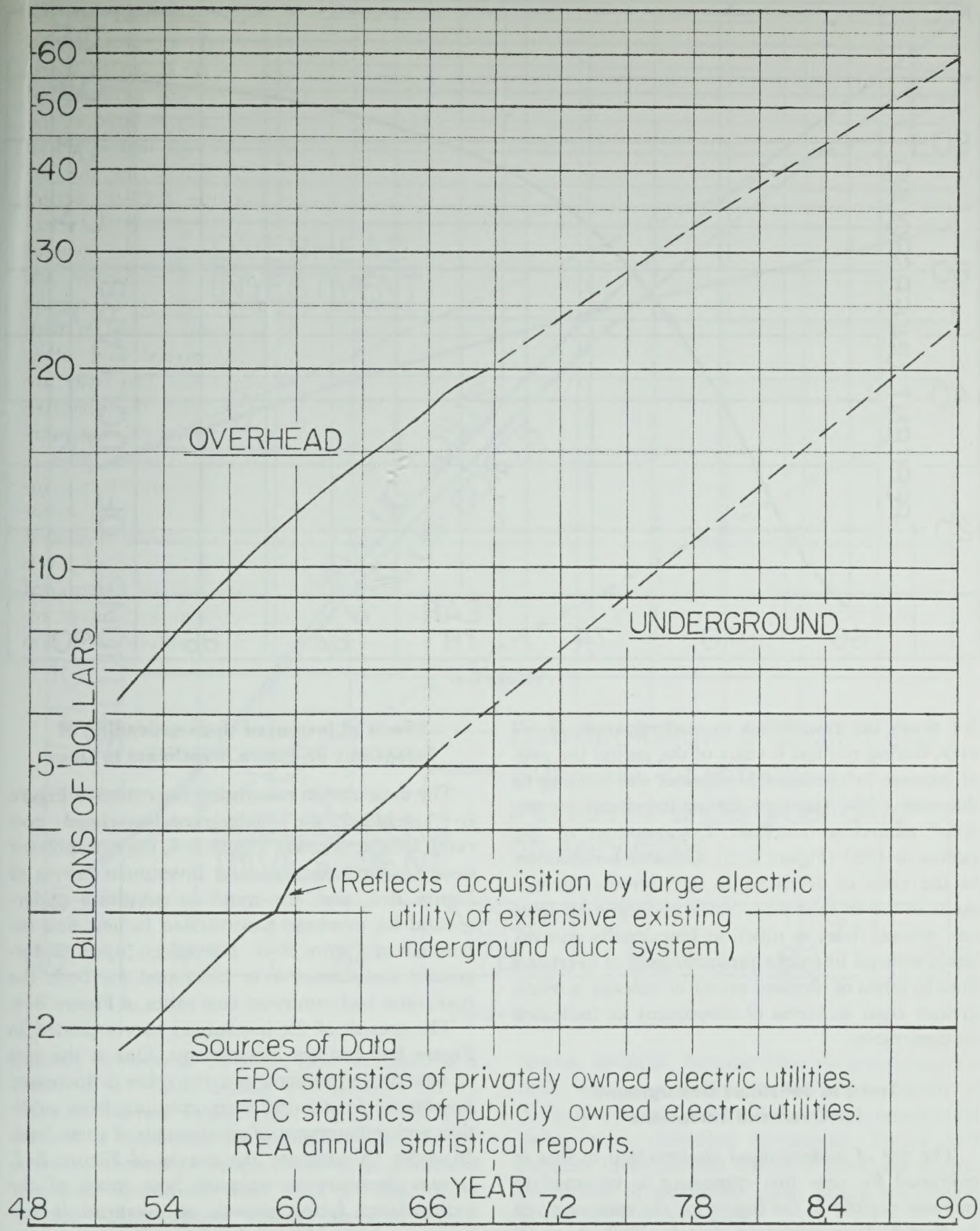


FIGURE B–5.

overhead cost ratios from the 1967 level to the 1980–90 levels of Table B–b and provide a basis for computation of the impact of increased undergrounding during this period upon distribution system investment.

Trends of Investment in Overhead and Underground Lines

Throughout the period 1952–67, total utility investment in overhead lines was approximately

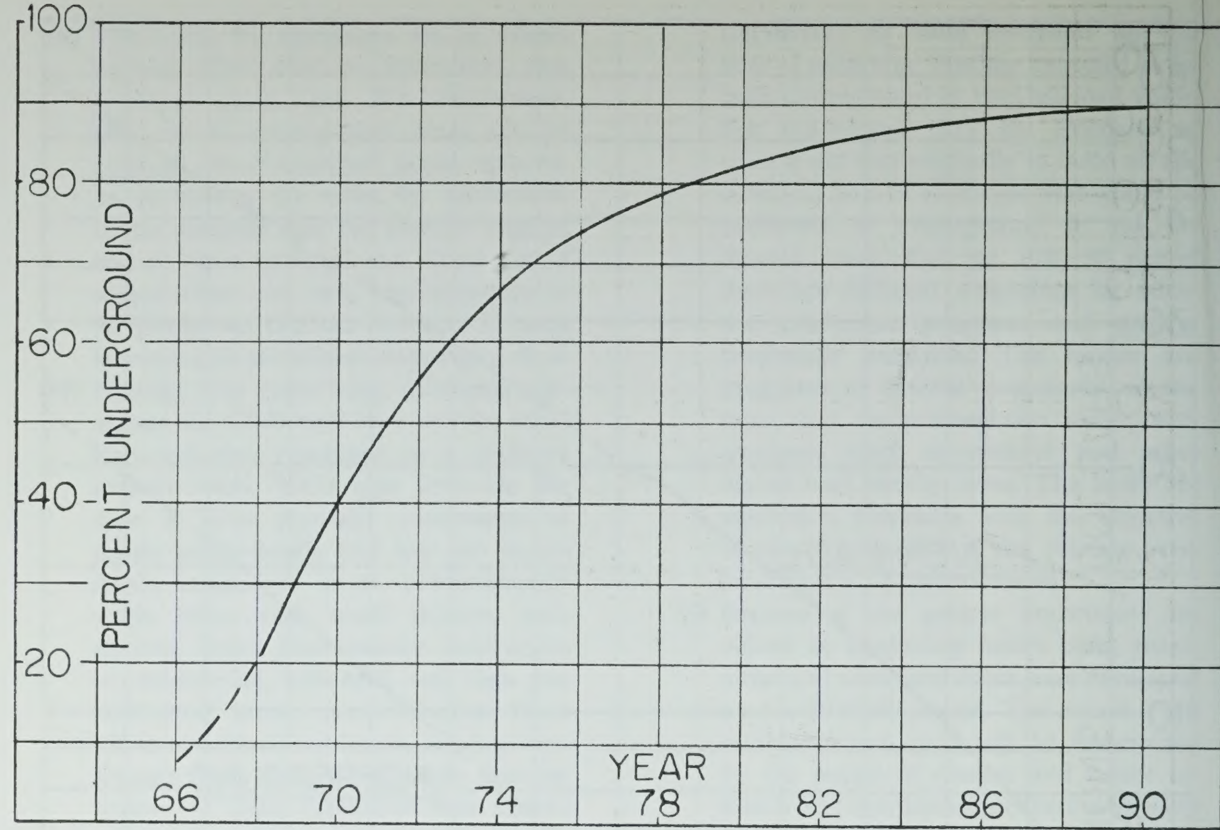


FIGURE B–6.

3.4 times the investment in underground. However, during the last 6 years of the period the rate of increase in overhead investment was tending to decrease while the rate for underground investment tended to increase. Extrapolation of the curves to 1990 (Figure B–5) indicates a reduction in the ratio of overhead to underground investment to 2.5 in that year. Since underground lines cost several times as much as functionally equivalent overhead lines, the predominance of overhead lines in terms of physical extent or mileage is much greater than in terms of investment as indicated by these ratios.

Trend to Substitute Underground for Overhead Extensions

The use of underground construction in lieu of overhead for new line extensions is expected to increase rapidly in the future for the reasons given in Part I. It is estimated that in 1968 about 20 percent of all of the new lines of types that would have been built overhead under historical practices (measured in dollars of equivalent overhead cost) were built underground. This percentage is expected to increase to 70 percent by 1975 and to 90 percent by 1990 as shown in Figure B–6.

Effects of Increased Undergrounding of Extensions on Future Investment in Lines

The data used in computing the curves of Figure B–7 included the underground-overhead cost ratios for extensions of Figure B–4, the extrapolated overhead and underground investment curves of Figure B–5, and the trend to substitute underground for overhead construction in new line extensions of Figure B–6. The effects upon underground investment were computed for both the maximum and minimum cost ratios of Figure B–4.

The growth of the investment curves plotted in Figure B–5 has two components. One is the cost of new line extensions and the other is increased investment in existing lines resulting from addition and replacement of components of these lines. In order to compute the curves of Figure B–7, it was necessary to estimate how much of the extrapolated future growth of overhead investment would be the result of new line extensions. It was estimated that the annual expenditure for this purpose per added customer served would be equal to the current reproduction cost of all existing overhead lines divided by the total number of existing customers served. Current reproduction cost of the existing lines was estimated to be the

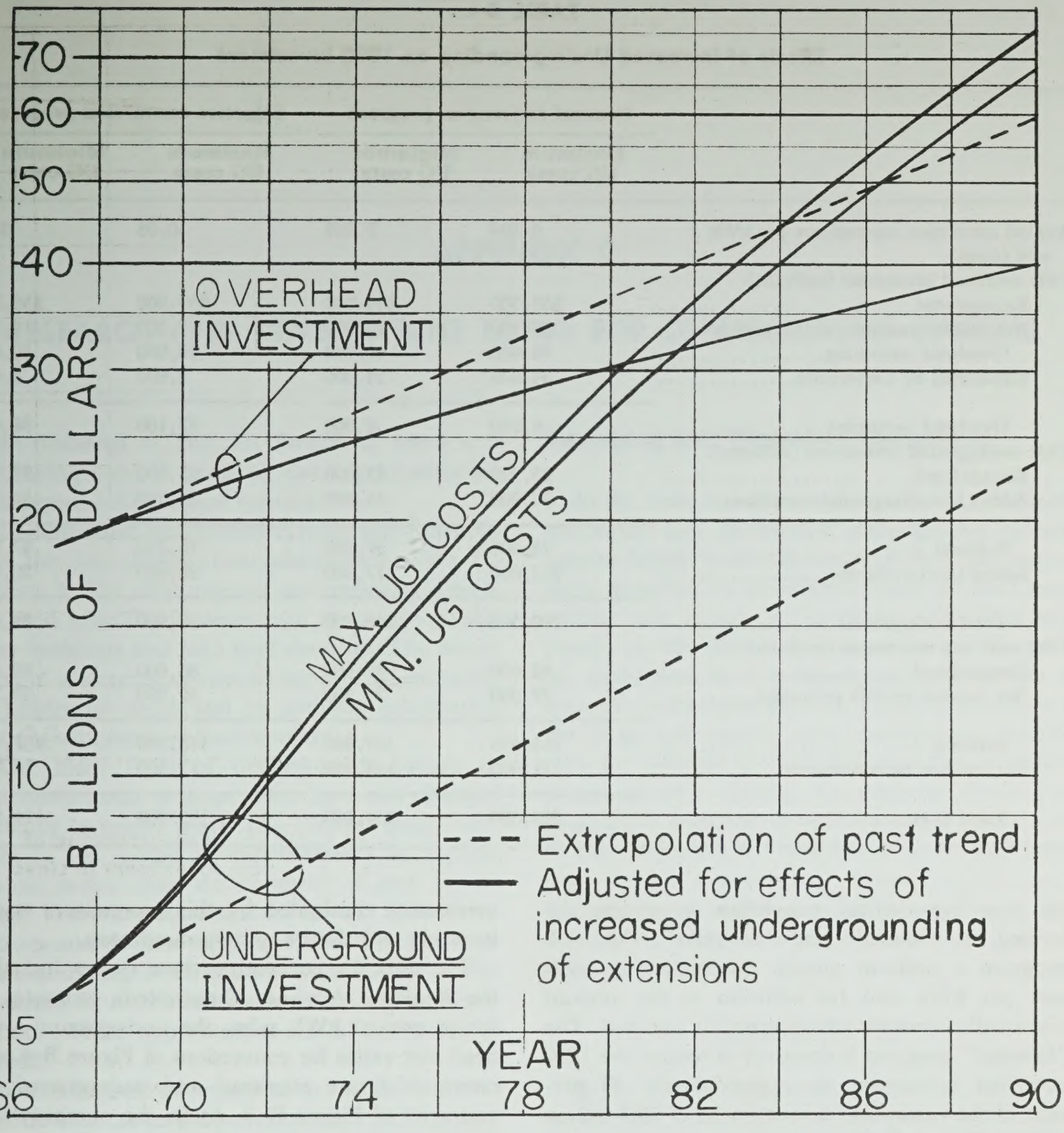


FIGURE B–7.

existing investment in these lines divided by a factor of 0.7 (representing cost inflation for 15 years at the rate indicated by Figure B–3). This method of estimating the annual expenditure for overhead extensions results in the total growth of overhead investment from 1967 to 1990 being divided approximately equally between extensions and increased investment in existing lines; and in an average growth rate in the investment in existing lines of about 2.7 percent.

The substitution of underground for overhead extensions as projected in Figure B–6 will reduce future overhead and increase future underground investment by more than just the costs of the extension involved, because after the extensions are built subsequent additions and replacements of components of them will add to underground rather than overhead investment. Figure B–7 includes these indirect effects of increased undergrounding of extensions upon future investment as well as the direct effects.

The trend to increased use of underground construction for extensions increases underground investment much more than it reduces overhead investment, and consequently results in a large increase in total investment.

Table B–c shows estimated effects upon 1990 investment in overhead and underground lines

TABLE B–c

Effects of Increased Undergrounding on 1990 Investment

	General conversion program		Selective conversion program	
	Maximum UG costs	Minimum UG costs	Maximum UG costs	Minimum UG costs
Annual conversion expenditure per kWh sold (cents)	0.304	0.263	0.03	0.03
1990 overhead investment (millions):				
Extrapolated	$59,300	$59,300	$59,300	$59,300
Avoided by underground extensions	19,300	19,300	19,300	19,300
Overhead remaining	40,000	40,000	40,000	40,000
Eliminated by conversions	34,000	34,000	2,900	3,400
Overhead remaining	6,000	6,000	37,100	36,600
1990 underground investment (millions):				
Extrapolated	23,300	23,300	23,300	23,300
Added by underground extensions	52,200	44,600	52,200	44,600
Subtotal	75,500	67,900	75,500	67,900
Added by conversions	205,000	177,300	20,400	20,400
Total underground	280,500	245,200	95,900	88,300
1990 total line investment (millions):				
Extrapolated	82,600	82,600	82,600	82,600
Net increase by UG extensions	32,900	25,300	32,900	25,300
Subtotal	115,500	107,900	115,500	107,900
Net increase by conversions	171,000	143,300	17,500	17,000
Total lines	286,500	251,200	133,000	124,900

for two hypothetical conversion programs described as "General" and "Selective". For each program a uniform annual conversion expenditure per kWh sold (in addition to the amount historically spent for this purpose) is assumed. The "General" program is designed to reduce the 1990 overhead investment to approximately 10 percent of the extrapolated investment of 59.3 billion dollars (Figure B–5), and the increase in annual conversion expenditures per kWh to accomplish this depends upon the future trend of underground construction costs. The "Selective" program assumes an added annual conversion expenditure of .03¢ per kWh sold, and the amount of overhead investment eliminated by this expenditure varies inversely with future underground costs.

The data for computing these curves included the Regional Advisory Committee's estimates of future annual kWh sales, the underground-overhead cost ratios for conversions of Figure B–4 and curves of future overhead and underground investment of Figure B–7. As in the computations for Figure B–7, it was necessary to take into account the fact that additions and replacements of components of the lines subsequent to conversion would have the effect of increasing the underground rather than the overhead investment.

APPENDIX C

RESEARCH AND DEVELOPMENT NEEDS FOR UNDERGROUND SYSTEMS

As discussed in Part II, Section 5, there is a continuing need for research and development for underground distribution systems.

Underground distribution systems fall generally into the two classifications discussed in Part II, Section 3. The older types of underground systems are used generally in downtown areas with multistory buildings and high load densities. The newer types of underground systems are utilized generally in residential areas and in outlying commercial sections with medium load densities.

The older types of underground systems in downtown areas of larger cities have not changed radically in recent years. The changes made have been in the nature of improvements to existing devices rather than development of new equipment. There are opportunities for use of the procedures and devices being developed for the newer types of underground systems in the extension and modification of the older downtown underground systems. These opportunities should not be overlooked.

In this report, the emphasis is on development of devices for use on the newer types of underground systems, but as indicated, it is expected that such equipment will find use in the older systems in the downtown areas. Some utilities are now doing this. As time goes on, the practices of the two types of systems may be expected to come closer together.

The developments discussed in the following sections are those which seem pertinent at this time. It is hoped that the suggestions made will be of value to manufacturers who produce the devices mentioned and to users who will incorporate them into underground distribution systems. It is not be be inferred that future developments should be limited to the devices mentioned. On the contrary, the discussion of these items should stimulate development of other new types of equipment as well as the devices discussed.

Switching and Protective Equipment

As the areas served by residential and combined residential and commercial underground systems become larger, it is no longer possible to use equipment mounted on an adjacent pole for fault protection and circuit sectionalizing. The first approach to this problem has been to put the pole top equipment in a compartment mounted on a concrete pad at ground level. These compartments are large and usually quite conspicuous because they are installed in locations accessible to utility personnel who operate the switches. Protective equipment installed in above-ground enclosures is not aesthetically compatible with the total underground system using below-ground transformers, but is being installed by an increasing number of utilities as a means of eliminating overhead construction.

Switching Devices

As an initial approach, protective and sectionalizing switching equipment is needed for underground systems to render the same quality of performance as the devices which have been developed over the years for overhead systems. Additional refinements of control and automatic operation should then be considered. The equipment for use on underground systems must be suitable for the environmental conditions encountered, which usually are more severe than those for overhead systems.

Most of the submersible switching devices which are now available were developed for use in large underground vaults. These switches are too large and cost too much installed for use in residential underground systems.

The protective and sectionalizing devices for underground residential and commercial systems

should preferably be suitable for universal installation in either above-ground or below-ground enclosures. Those designed for underground must be completely enclosed with no exposed live parts and should neither emit fire nor hot gases during circuit interruption, nor build up internal pressures which require venting for relief. They should also have accessible terminations for easy insertion or removal.

The vacuum switch, or a comparable enclosed device, is needed to eliminate the undesirable characteristics of the oil switch for use in below-ground enclosures. Single-pole submersible switches are required for protection and sectionalizing of single phase underground primary circuit branches. Similarly, three pole devices are needed for three phase applications. These switches should be made available in the three types listed below:

a. Manually operated.
b. Automatically or remotely operated without interrupting ability (Similar in automatic operation to the single-pole sectionalizer developed for overhead systems).
c. Automatically or remotely operated with interrupting ability.

All of the switches should have sufficient capability to withstand the effects of inadvertently closing into a fault. Since the switching requirements of the three types are somewhat similar, it may be possible to use the same basic switching unit for all of the devices, with special adaptations and different control mechanisms for the indicated applications.

A single-pole 15 kV vacuum interrupter suitable for installation in below-ground enclosures is now available. Manufacturers have indicated that development is underway of other single-pole and of three-pole devices with automatic controls.

Fuses

An encapsulated fuse is needed to protect the single phase branches of an underground primary circuit. Such a fuse might resemble a cable splice physically and be suitable for installation in below-ground enclosures. Development work should be done to produce an encapsulated fuse for this application. A necessary feature is ease of removal and replacement of a unit which has operated.

Automatic Control Mechanisms

For automatic control of switches in below-ground enclosures, control mechanisms are needed with response characteristics similar to those of substation relays. These control mechanisms are designated as sensors rather than relays to point out that relays of presently available types are not suitable for the intended application. The sensors should be submersible, encapsulated, plug-in modules which will retain their initial characteristics without adjustment for 20 to 30 years of operation in below-ground enclosures.

The following types of control devices should be developed to provide the desired flexibility in the application of switching equipment:

a. Voltage sensor, responsive to pre-determined voltage level.
b. Current sensor, with selection of pre-determined time-current characteristics.
c. Rate-of-rise sensor, to recognize abnormal condition within first half cycle.
d. Time measuring device, for introduction of deliberate time delay.

It is anticipated that there will be need for more automatic sectionalizing of underground distribution circuits than is now considered necessary for overhead circuits. There is a trend toward primary voltages for underground systems higher than the predominant 15 KV level and this trend will be accelerated when suitable sectionalizing equipment for operation at the higher voltages becomes available. The economy of the higher voltage circuits is obtained only if they are loaded to their full capability. Ratings of circuits operating at the 15 kV level may also be expected to increase as higher load densities develop. It appears reasonable to expect that heavier circuit loadings will require more automatic equipment to provide better service continuity. Consequently, sophisticated applications can be justified for the control devices needed.

Remote Control Mechanisms

Remote control of underground distribution circuit sectionalizing is a definite possibility. Switches installed in underground circuits should be suitable for future addition of remote control modules. Possibilities for computer control of distribution circuit sectionalizing are discussed in Part II, Section 4.

Cables

The electric cable was one of the first pieces of equipment developed for the embryonic electric system. Improved cable designs have continued to evolve, and there is still work to be done to de-

velop optimum designs for the indicated applications.

Insulating Materials

The insulating materials used in early cables were of natural origin. After trials of other materials, paper (impregnated with oil) and rubber were the ones which achieved general use.

Impregnated paper has been the most widely used insulation for underground transmission and distribution primary systems. For successful operation, this insulation must be protected from contaminants and moisture. This requires a moisture barrier, generally applied in the form of a metal sheath over the cable. Terminations must be sealed so that moisture is not admitted under any condition of operation. Impregnated paper insulated cables will continue to be used for many applications, particularly in transmission systems. The techniques involved in the use of impregnated paper insulated cables are covered adequately in other publications.

Natural rubber became scarce and expensive during periods of national emergency. This led to intensive laboratory research to find suitable substitute materials. The result was the production of synthetic rubber-like materials, which have good electrical and physical properties and are suitable for cable insulation.

The distances between transformers in residential underground systems are relatively short. Consequently, cable lengths are short and a large number of cable terminations are required. This made it desirable to look for cable insulation which did not require a metal sheath and metal working procedures to seal the terminations. This has spurred the search for insulating materials which are inherently resistant to moisture penetration. Materials have been produced which are superior to natural rubber in electrical and physical characteristics. The first materials were thermosetting in nature and required heat treatment after extrusion to stabilize the cable insulation.

Continuing laboratory work led to the development of thermoplastic materials which are excellent cable insulations. As the name indicates, these materials become plastic when heated beyond a certain critical temperature. Thus, heating of cable insulation must be controlled to prevent damage to cables in operation. In the case of polyethylene, this difficulty has been overcome to some extent by cross-linking the material which changes it from a thermoplastic to a thermosetting compound.

Many of the cable manufacturers have laboratories for exploration of new developments as well as for production control. The manufacturers have been quite successful in developing additives and treatments to improve the characteristics of available basic materials used as cable insulations. These treatments are proprietary in nature and are the subject of competitive claims of superior performance. The manufacturers should be encouraged to continue their research.

Laboratory development of basic materials for use as cable insulations has been restricted because of the relatively small purchases of the materials as compared with many other commercial applications. Frequently, the cable industry has been placed in the position of adapting available materials for use as insulations. It is interesting to speculate what could be accomplished if the basic molecule of a new material was designed to produce the optimum combination of electrical and physical properties as an insulation for distribution system cables.

The Electric Research Council now has a project under way to investigate basic new materials for insulation in cables operating at 500 KV or higher. It is hoped that the materials may be suitable for insulation of lower voltage cables as well as high voltage transmission cables.

Conductor Materials

Until recent years copper was the material used predominantly for cable conductor. Copper has excellent electrical conductivity and superior mechanical characteristics.

During periods of national emergency, the stockpiling of copper for military uses sharply reduced the amount of the metal available for other applications. The recurring copper shortages caused many electric utilities to adopt aluminum as a cable conductor, particularly for the lower voltage cables. This was done first on a trial basis and then on a permanent basis after the initial trials were successful. Recently, cables with sodium conductors have become available. A number of trial and test installations have been made. Should the use of cables with sodium conductors prove desirable, special installing and operating procedures will be necessary.

Copper is one of the relatively rare metals in the earth crust. It is used in many applications where it is difficult to find an acceptable substitute. This includes the bare concentric neutral conductors of URD type primary cables. Developments

leading toward the use of the more abundant metals, such as aluminum and sodium, for cable conductors should be encouraged. The metal to be used for a particular installation is generally dependent on relative price and availability at the time the installation is made.

Specifications

Specifications for cables with impregnated paper insulation are prepared by the Association of Edison Illuminating Companies, a group representing cable users. The corresponding specifications for cables with other insulations are prepared by Insulated Power Cables Engineers Association, a group representing cable manufacturers.

It has been proposed that, as a matter of basic philosophy, all cable specifications be prepared by user groups. The suggestions and proposals of the cable manufacturers representatives would, of course, be given due consideration. Preparation of specifications for insulations other than paper by a user group has been started and is expected to continue.

With extruded rather than taped insulations it is more difficult to specify routine factory tests which will insure the production of quality cables on a day-to-day basis. The possible harmful effect of an imperfection in an extrusion is much greater than that of a defect in a single tape in multilayer laminar construction. When extruded cables are made for higher voltage operation, the electrical stress on the insulation is deliberately increased in order that the dimensions of the manufactured cables are kept within workable limits. Thus the necessity for adequate factory tests to detect imperfections is increased.

The manufacture of a relatively long length of high voltage cable with extruded insulation becomes a matter of probability in producing the length of cable without a single detectable imperfection. With present technology, any defect which may be found with the most sensitive equipment might result in failure of high voltage cable sometime during its service life. Work should continue on the development of better techniques for the testing of cables.

Cable Terminations and Splices

For cables with extruded insulations, factory made terminations and splice kits have been developed which may be applied to the cables with a relatively small amount of work in the field. The following discussion is confined to terminations and splices of this type.

Primary System Devices

Factory produced terminations and splices generally depend upon the characteristics of an elastomer material to achieve and maintain a tight fit over the cables to which they are applied. The tight fit is required to prevent the formation of voids in areas of high electrical stress which may break down and cause failure. It is also fundamental that the entrance of moisture during all operating conditions must be prevented.

It is necessary to maintain the continuity of cable shielding over the terminations and splices. Two general methods have evolved. One utilizes a metal enclosure for the termination or splice and the other uses semi-conducting material for the outer shielding layer. Terminations with rating of 200 amperes are available in several types, including separable connectors which may be used to sectionalize the primary system. The separable connectors are available in load break and non-load break types. Standardization of critical dimensions of the connectors of the various manufacturers is now in process.

A termination with a rating of 600 amperes is now available. This is not a separable connector. It can be taken apart with a wrench when de-energized and is used as a manual disconnecting device recognizing this limitation. Development work is in progress on 600 ampere separable connectors.

Designs of factory made separable connectors and splices with voltage ratings up to 35 kV have been announced. Manufacturers should be encouraged to continue development of these devices so that they can be available as soon as possible. Connectors for use as manual sectionalizing devices are an integral part of the newer types of underground distribution systems. The flexibility which they offer should be made available without unnecessary delay for higher voltage underground primary systems.

Secondary System Devices

For the connection of secondary conductors to transformer terminals and of services to secondaries, many types of connectors and kinds of arrangements are now used. Standardization on a reasonable number of types, or at least a considerable reduction in the number of arrangements

now used, would be advantageous to both manufacturers and users.

Fault Indicators

In contrast to overhead lines, faults on underground circuits are not visible and usually cannot be readily located by patrol and inspection.

Sensing Devices

If adequate automatic sectionalizing of underground primary circuit is provided, as discussed in this appendix, there is still the problem of exact location of the fault within the sectionalized portion of the circuit. When the fault has been located and isolated, customer service may then be restored, to the maximum extent possible with the circuit arrangement, without waiting for repair or replacement of faulted equipment. Development work should continue leading toward improvement of devices indicating flow of fault current. Design of equipment which can be seen from ground level is urgently needed. For underground lines located along the street, such visibility from a patrol vehicle would save time in fault location.

Remote Indication

An objective for future distribution systems is the development of devices that will transmit knowledge of the flow of fault current to a central location. From such indications, the fault location can be pinpointed and corrective action started immediately. Communications systems designed for fault indication systems should be suitable for later addition of other information, if this becomes desirable. Possibilities for computer control of distribution system operation are discussed in Part II, Section 4.

Capacitor Installations

Capacitors installed on distribution primary circuits may be unswitched, switched automatically in accordance with indication of current, voltage or temperature, or switched by remote control. Capacitors are an important device for regulating distribution system voltage and control of reactive current flow. It has been usual practice to install overhead type capacitor units on poles at selected locations in overhead distribution systems.

As more of the distribution system is placed underground, it becomes more difficult to find locations for the installation of overhead type capacitor units. To overcome this difficulty, manufacturers are working toward the development of capacitor units suitable for installation in below-ground enclosure or for direct burial in the earth. Dissipation of the heat produced by capacitor losses is a problem, particularly with the direct burial units. Economical submersible switches and controls are also needed.

Work should be continued leading toward the development of submersible capacitor units so that underground primary circuits will have the same flexibility in control of voltage and var flow as overhead primary circuits. The cables in the underground distribution system produce some reactive current, but not enough to satisfy reactive load requirements. Capacitors needed to provide the necessary reactive correction for distribution system loads should be installed as close to the loads as is practicable.

Installation Methods

Many of the early installations of underground distribution systems were done on a custom basis and naturally the cost of such projects was relatively high. Some cost reductions have been achieved but there is ample opportunity for standardization of procedures and further reductions in cost of installation.

Improvements in Procedures

The placing of cables in the ground is a relatively large component of total system installation cost. It is probable that appreciable savings can be realized if better methods can be developed.

Installation of power and communication cables in a common trench, is a practical and economical procedure now in use. Additional savings are derived from random separation in joint trench construction, since the need is eliminated for partial backfill to provide vertical separation, or for wide trench and control of cable position to obtain horizontal separation. A further advantage is the avoidance of possible damage to existing cables when a new customer service is installed.

A Joint Edison Electric Institute-Bell Telephone System Subcommittee reported successful experience with more than 18 million trench feet of random separation construction. The recommendation of the subcommittee report and the revisions given in the National Electrical Safety Code Supplement #2 are in complete agreement

and outline the usual practices followed by power and telephone utilities. Use of random separation presents opportunities for cost savings which should be pursued.

Trenchers have been generally used for cable installation. Cables can also be installed by plowing, with less disturbance to the ground surface, and, under some circumstances, with lower costs. Work to date on vibrating plows seems promising. Potential improvements include reduction in required draw bar pull and creation of good cable environment by surrounding the cable with fine material vibrated into place. Plowing is most advantageous for long cable runs such as in rural areas.

Development of a device to do the entire job of placing equipment underground should be investigated. For example, a single device might have a vibrating plow attachment to place the cable and coring attachments for installation of below ground enclosures and for tunnelling under paved streets or driveways.

New Concepts

There is need to investigate new concepts for the placing of cables in earth. Development progress has been reported on a "guided mole"; a device shaped like a projectile which can be driven through the earth. This creates a tunnel into which cables are pulled. It is understood that methods for application of power and for control of horizontal and vertical movement are being studied. The "guided mole" should be useful in installation of cables in unpaved earth and be particularly advantageous for cable installation under pavement, lawns, etc. In built-up areas where power and communication facilities are to be converted to underground, cable installation under existing pavement and lawns using "guided moles" may become the usual procedure.

Conversion of Overhead to Underground

More conversion of overhead lines to underground is expected in the future. Utility engineers should be prepared to make such conversions as efficiently and economically as possible where they are required.

Development of Universal Equipment

One possible method of preparation for future conversion of the overhead system to underground operation is the use of universal equipment which could operate on the overhead system initially, yet be suitable for later use on the underground system. It may be that some of the devices developed for underground distribution systems could find use on overhead systems, at least for an interim period, where conversion is contemplated.

However, due to the fact that the overhead system will be in existence well beyond the useful life of many of its components, and to the fact that the rapid growth of the underground system will for some time to come be limited principally to new extensions rather than conversions, it is essential that the most economical equipment for use on each system continue to be developed. At some time in the future, economics will dictate and thereby promote the increased development of universal equipment.

Service Reliability

As customers use more electricity and become increasingly dependent upon the benefits so derived, the requirement for reliability of the service increases. Basically, the expected service reliability for the newer underground systems serving single and multi-family residences and commercial installations should be as good as that which has been provided from the overhead system. An industry objective should be betterment of service reliability over this base level by improvements in equipment and in operating procedures.

Improved Equipment

As outlined in this report, there is an increasing trend toward the use of higher primary voltages. To obtain the economy of the higher voltages, loadings of primary circuits must be increased. With higher circuit loadings, each circuit may have more exposure to faults and a total circuit outage will interrupt more load.

In order to compensate for the increased exposure, greater use and improved coordination of automatic sectionalizing devices will be necessary. When a total circuit outage occurs, partial service should be restored promptly by means of automatic switching arrangements, remote control of switches, or other sophisticated techniques. By appropriate circuit design and use of advanced techniques, it should be possible to increase circuit loadings and also improve rather than deteriorate service reliability. Development of reliable and

economical equipment for this purpose should be a major industry objective.

Improved Procedures

Improvements in operating procedures for sectionalizing distribution primary circuits must keep pace with the development of equipment. In fact, the study of proposed improvements in procedures should come first so that the results may be presented to equipment manufacturers to stimulate and guide them in the development of new devices.

It should be acknowledged that utilities have not furnished the manufacturers of sectionalizing devices with clear cut objectives for development of what is needed for underground distribution systems. Industry groups should develop and publicize such objectives at the earliest possible moment.

A REPORT TO THE FEDERAL POWER COMMISSION

THE METHODOLOGY OF LOAD FORECASTING

PREPARED BY

THE TECHNICAL ADVISORY COMMITTEE
ON LOAD FORECASTING METHODOLOGY
FOR THE NATIONAL POWER SURVEY

1969

PREFACE

The need for a comprehensive study of the methodology of electric utility load forecasting has been recognized by many in the electric utility industry and government. No basic reference source has existed covering the data requirements and current methods and techniques used in this area of utility operations. The Federal Power Commission, cognizant of this need, established the Load Forecasting Methodology Committee as one of four technical advisory committees formed to assist the Commission in updating the National Power Survey of 1964. The assignment given this Committee was to determine the state of the art of load forecasting, to assess the need for improved methods and techniques and to suggest means of meeting such need.

The Committee's study of which this report is the result was conducted in cooperation with many segments of the electric power industry. The Committee wishes to express its appreciation to all contributors who have given time and assistance in preparation of this study. There are too many to name here individually, but thanks are due particularly to members of the Commission staff who worked with the Committee, to the Regional Advisory Committees who helped obtain data from utilities and to the many electric utilities who submitted statistical data and other information regarding their operations and load forecasting procedures.

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CHAPTER I—INTRODUCTION

A. Nature and Purpose of Forecasting

Most planning, construction and operating activities of an electric power system are based on expected future conditions. As with all future events, there exist varying degrees of uncertainty associated with each. In forecasting, the near and intermediate future are of greatest importance in influencing the success a utility has in achieving its objectives. Important decisions for the near future can be made with reasonable assurance that such period will resemble the recent past and most problems to be faced will resemble problems solved, or at least encountered, in the past. As forecast limits extend further into the future, consideration of new and different problems is required. In some of these activities the significant future extends through several decades.

The process of forecasting electric utility load follows the same principles that apply to all forecasting. "Forecasting" as the term is used in this report refers to the systematic process of defining the future in sufficient quantitative detail to permit important decisions to be made. Certain methods and techniques have been developed for load forecasting which have produced reasonably satisfactory results to date. Increasing pressures within and upon the industry are placing premiums on further improvements in forecasting methods.

A fundamental uncertainty in forecasting exists no matter how much data are collected or how sophisticated the approaches used may be. Even so, it is reasonable to expect that the collection of better measures and the application of improved techniques will improve forecasting accuracy.

For the purposes of this report, three terms are defined in a specific way: load, demand and energy. Frequently in the industry these terms are used interchangeably. Load, here, is utilized as a general term with reference to usage of electricity and encompasses both of the other terms. Demand represents the usage of electricity at a point in time—usually an hour—stated in kilowatts. Energy represents demand integrated over time, stated in kilowatthours.

B. Scope of Report

The major purposes of this report are to familiarize members of the industry with the various utility forecasting techniques being used and to present forecasting techniques being successfully applied in other fields, together with an understanding of their limitations. It is hoped that this report will lead to improved forecasting as well as encourage more effective data reporting and collecting practices within the industry.

No attempt has been made by this Committee to forecast demand or energy. Rather, the work of the Committee has been devoted entirely to the methodology of load forecasting and has further been limited to system-wide forecasting, primarily for bulk power supply planning. The report includes a description of the principal types of load forecasts being made at the present time and the purposes for which they are made.

Separating total load into various consumer classifications and load types is discussed, as is the use of demand and/or energy as bases for forecasts. The increasing use of electric air conditioning and space heating is having a substantial effect on both summer and winter peak demands; for this reason, special consideration is given to the relationship between weather conditions and electric load. The various types of data employed are analyzed and evaluated for their adequacy in forecasting electric demand and energy, as are the possibilities of improving data sources and collecting techniques. Based on a survey of 30 utilities conducted by the Committee, forecasting methods as practiced in the industry are described and analyzed.

Methods and techniques used for each type of load forecast and their relative accuracies are discussed. Special circumstances that have an effect on load characteristics and trends are pointed out. The report emphasizes the need for the development of new methods that are responsive to changes in the nature of demand and energy growth. Attention is given to the possible further impact on forecasting of expanded use of modeling

techniques and computer applications. Included in the Appendices are detailed descriptions of specific forecasting techniques, a bibliography of selected papers on topics covered in the report, and a list of historical and forecasted data available from government and industry.

C. Summary

1. Forecast Methodology

All load forecasting methods appear to include the same fundamental steps: (1) Collect historical data and adjust them to achieve reasonable consistency over the desired time period; (2) Analyze data to determine the significant economic, demographic and climatic factors which have influenced load growth in the past; (3) Extrapolate significant causal factors into the future and determine the degree of uncertainty in each extrapolation; (4) Derive forecasts by considering the effect that these extrapolated factors are expected to have during the time period chosen; (5) Determine the relative degree of uncertainty in the forecast; (6) Periodically compare recorded performance with previous forecasts and make appropriate adjustments in techniques and assumptions.

Despite the many improvements being made in load forecasting data and methods, there is little that is mechanical in forecasting. Even the more sophisticated techniques do not eliminate the need for good judgment. They do provide a better understanding of the past and thus a better base on which judgments can be made on the likely shape of the future.

2. Data

A large volume of many types of data is available to the forecaster, both within the utility system itself and externally from industry, government and other sources, but its usefulness is often impaired by lack of definition and consistency. Major deficiencies frequently associated with data from sources outside of the utility are their incompleteness, or incompatibility in time periods or in area covered. Data acquisition and dissemination are costly, which makes it important that the purpose and value of data used in forecasting be given full and careful consideration in advance. Wise selection and use of data are of major importance in achieving accurate forecasts.

3. Current Load Forecasting Techniques

The Committee found many load forecasting methods and techniques in use today. These differ not only in technique but also in degree of detail and sophistication. Specific choices reflect individual system requirements such as variations in geographic and economic conditions. It is the Committee's conclusion that because of differences in load characteristics no single method or technique is best for all utilities, but rather each utility must consider its own special conditions and requirements in developing or adapting a method for its use.

4. Future Techniques

Load forecasting methods and techniques used in the past have served the industry well. However, the wider swings in loads experienced by many systems in recent years, together with the availability of greater computational capability, have intensified the search for new forecasting techniques. Recent experimentation with mathematical approaches, econometric models and computer techniques and further development of these and possibly others, promise improvement in the accuracy of future load forecasting.

CHAPTER II—NEED FOR LOAD FORECASTS

Estimates of both demand and energy requirements in the future constitute the foundation for planning in the electric utility industry. Every distributor of electric power, large or small, wholesaler or retailer, should have demand and energy forecasts available upon which to base its physical and financial planning. Others associated with the industry, such as suppliers, regulatory agencies and appliance manufacturers, also need such forecasts to carry out their functions.

A. Users

1. Electric Systems

Electric utilities plan the capacity of their physical system to meet expected peak demand requirements. Demand forecasts are the basis for planning additions to generating capacity as well as to transmission and distribution plant. In addition to maximum demand forecasts, the load shape (hour-by-hour demand estimates for the period) may influence the choice of kind of generating capacity. For example, peaking units or pumped storage, as opposed to base load capacity, might be used when maximum demands are of short duration. Such forecasts can also be useful for evaluating interchange capabilities and joint planning with other systems.

The combination of demand and energy forecasts forms a basis for planning fuel requirements. On a shorter term basis, daily and weekly demand and energy forecasts play an important role in the selection of an economical and reliable combination of resources for system operating purposes. For example, fuel costs between plants may differ substantially, while interruptible fuel supply contracts may dictate increased fuel costs at particular plants. Further, in the longer term instance of hydro-electric generation, only small amounts of firm energy may be available in dry years, thus requiring the generation of supplemental thermal energy. In wet years large amounts may be available to displace thermal generation.

Energy and demand forecasts are also the starting point for financial planning. The capacity and fuel strategies discussed above are based on these forecasts and in turn are translated into financial requirements. The carrying charge on plant and the cost of fuel are major costs of operating an electric utility. Estimates of many of the remaining costs are also based on either energy or demand forecasts, as are estimates of revenue. Energy forecasts are the basis of revenue planning. Together these factors form a financial plan. In addition, they are used to make rate analyses and to develop comprehensive marketing plans.

2. Regulatory Agencies

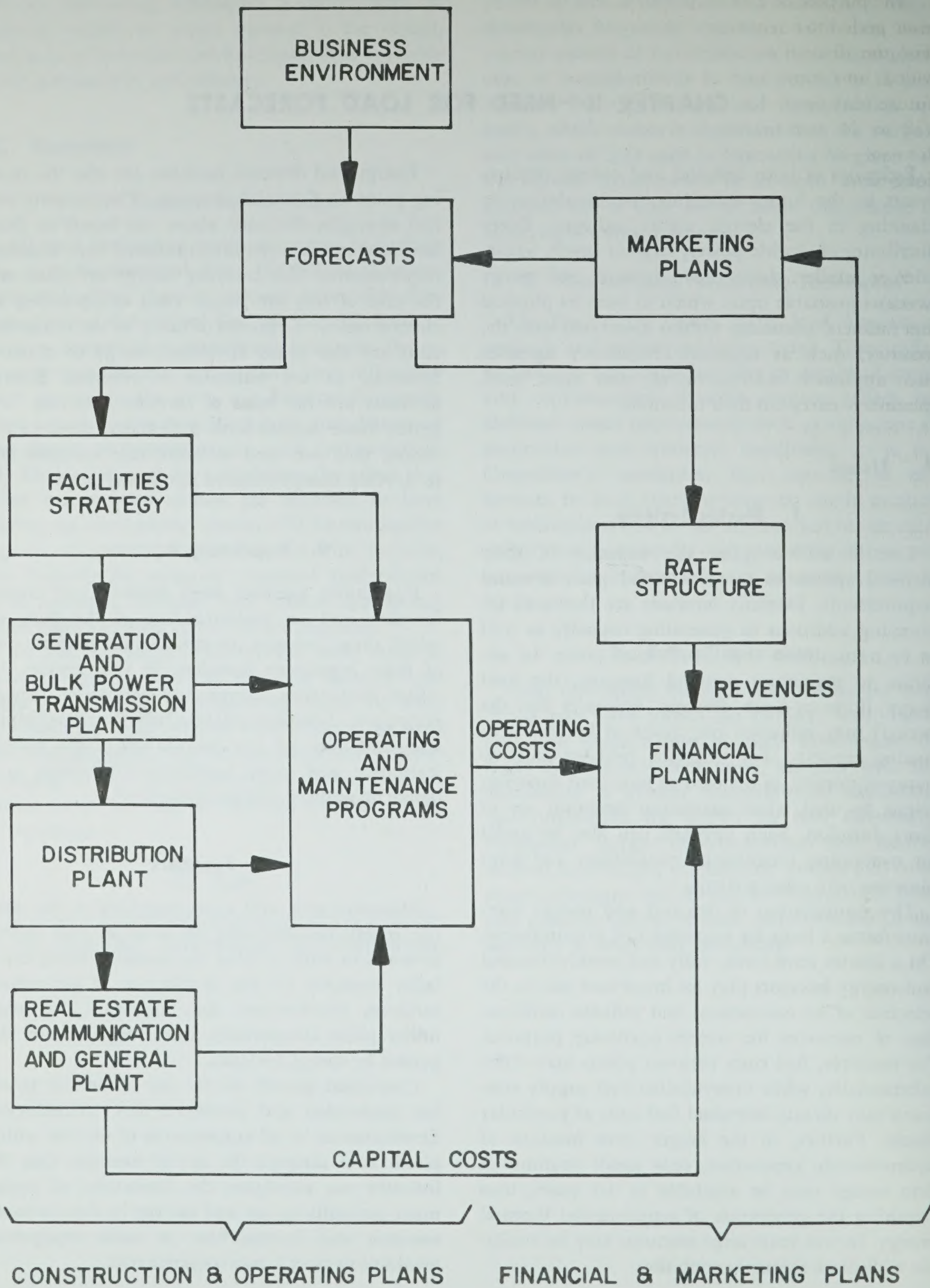
Regulatory agencies need demand and energy forecasts and an understanding of the basis on which these forecasts are made in the performance of their regulatory functions of rate review, facilities evaluation, interchange evaluation, merger review, etc. Forecasts will also help them to compile statistical data for the information of the public, legislative and other governmental bodies, academic institutions and manufacturers.

3. Suppliers

Manufacturers and other suppliers to the electric utility industry rely on demand and energy forecasts in order to plan the manufacturing capability required for the production of generators, turbines, transformers, line materials and other utility plant components. Fuel suppliers are also guided by energy forecasts.

Continued growth in the use of electric power has demanded and produced new technological developments in all components of electric utility plant. It is through the use of forecasts that the industry can anticipate the limitations of equipment currently in use and engage in the necessary research and development to make equipment available to meet future requirements.

FIGURE I
FORECASTING PLANNING CYCLE



B. Time Spans

The purpose of a forecast usually determines the time period to be covered and the accuracy needed. For the discussion that follows, forecasts are divided into four time categories: the immediate future (day or week), the near future or short-term (12 to 24 months), the intermediate-term (4 to 6 years—and now frequently to 8 years) and the long-term (10 to 30 years).

1. Immediate Future

Forecasting for the immediate future (day or week) is used in preparing the schedule for the operation of generating units, determining spinning reserve requirements, controlling equipment maintenance schedules, estimating gross revenue and planning outlays for fuel and purchased power. In such a short period, the fixed costs of utility plant, as well as the fuel reserve, are not subject to change. The forecasts become the means for operating the existing utility plant at the lowest incremental energy cost.

2. Short-Term

For the short-term forecast (12 to 24 months), as for the forecast for the immediate future, the fixed costs for generation and transmission have been established. However, in addition to being the basis for budgeting and planning operations for the lowest incremental energy costs, the short-term forecast is used for establishing maintenance schedules, firming up interchange potential, evaluating reservoir and streamflow conditions of hydroelectric projects, for nuclear fuel core management and for determining budget allocations for fuel and purchased power. This forecast may also be used to adjust distribution construction programs. There is also some, but more limited, opportunity to adjust transmission construction.

3. Intermediate-Term

The intermediate-term forecast (4 to 6 years—and often to 8 years) covers the most crucial time span in terms of planning of physical facilities, since lead times for adding generating capacity are generally of this length. Therefore, based on this forecast the final commitment to build generating facilities must be made. This involves such decisions as where and what kind of facility to build, whether to contract for power purchases or sales with neighboring utilities, and if a facility is to be built, securing permits, licenses, etc.

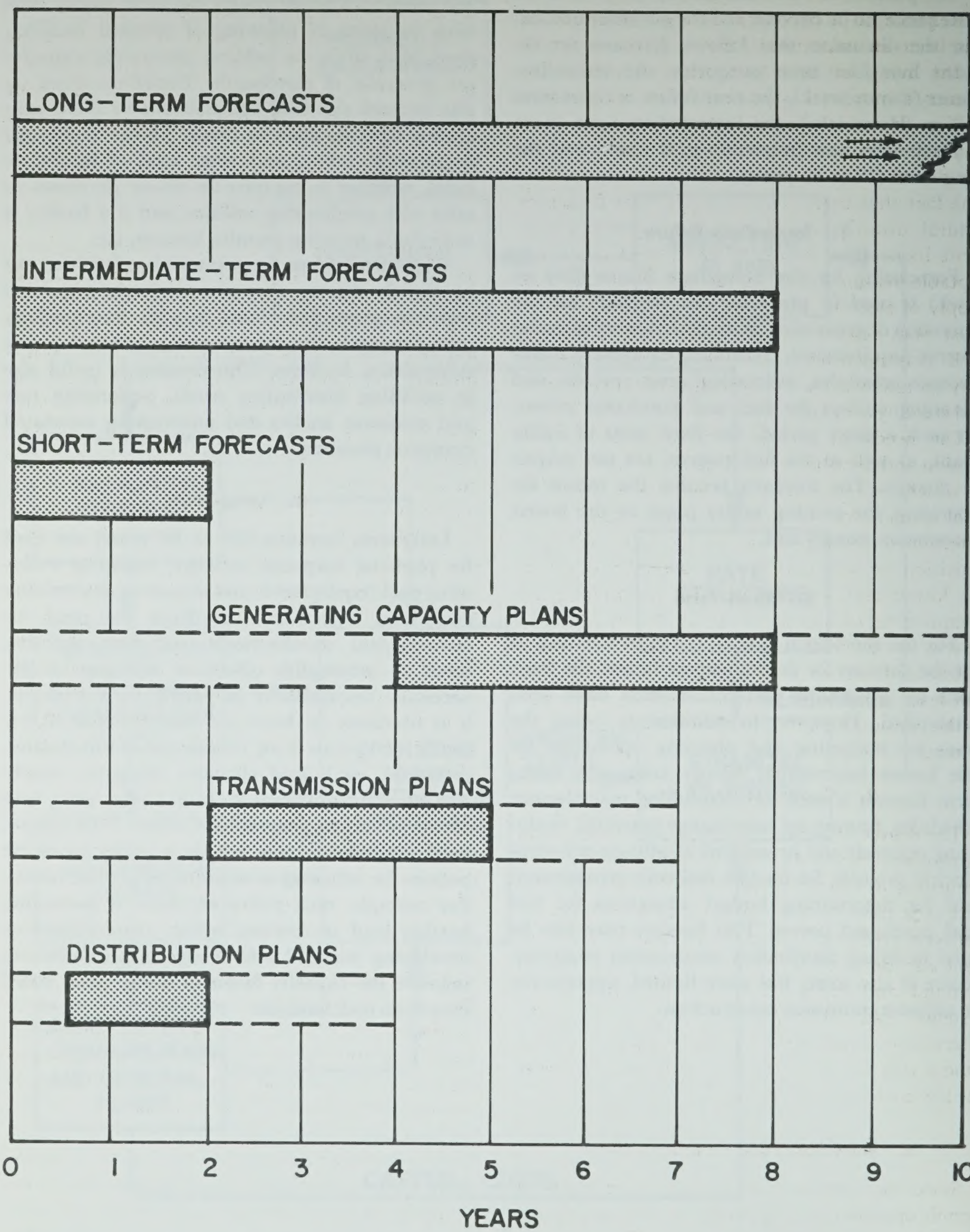
While lead times for transmission facilities can be slightly shorter, they are so closely associated with the generating plants that the intermediate-term forecast is also the determinant of bulk power transmission facilities. This forecast is useful also in outlining distribution needs, performing rate and economic studies and undertaking associated corporate planning.

4. Long-Term

Long-term forecasts (10 to 30 years) are used for planning corporate strategy, including evaluating fuel requirements and resources, determining goals and objectives, identifying the need for technological developments and for allocating funds to accomplish objectives and provide for necessary research. In preparing such forecasts, it is necessary to have an understanding of the trends of various load classifications (residential, industrial, etc.), load elements (diversity, hourly and monthly distribution, load factor, etc.), and trends in various geographical areas of the system. Such information may enable a utility to devise policies for adjusting to or influencing these trends. For example, such policy decisions as promoting heating load to increase winter requirements or developing seasonal interchange arrangements to improve the capacity factor of utility plant could stem from such forecasts.

FIGURE 2

TYPICAL FORECASTING & PLANNING HORIZONS



C. Accuracy

1. Significance

Reliance on a dependable supply of electricity has been an important element in the evolution of the living habits of Americans as well as the country's industrial operations. The reliability of service demanded by the American people requires that power be available for use whenever the demand occurs and whatever its magnitude. The fact that there may be equipment failure or natural disturbances that render certain equipment inoperative is seldom considered as an acceptable reason for the interruption of the bulk supply of electric power. As a result, the industry must plan reserve and standby systems to meet such contingencies. Accurate demand forecasts play an essential part in providing effective reserve and standby arrangements.

The needs for additions to generation, transmission and distribution facilities, the carrying costs of which represent such a major portion of the total annual cost of a utility system, are largely determined from demand and energy forecasts. Provision for adequate service to the consumer at the lowest cost, compatible with maintaining an adequate net income for the utility system, depends heavily on accurate demand and energy forecasts. Substantial variances from forecasts, therefore, can lead to inadequate service, unduly high costs to the consumer and/or inadequate income for the system.

2. Consequence of Errors

The degree of accuracy needed cannot be neatly categorized but is dictated by the probable consequences of error (where "error" is used in this text it is used in the statistical sense of variance between predicted and recorded results). The impact and duration of the consequence of errors in demand and energy forecasts will vary among systems. Such differences will depend upon the alternatives available to the system and upon the time period for which the forecast is made. Some of the key consequences are as follows:

a. Immediate Future and Short-Term

Since the primary use of these forecasts is to permit operation at the lowest incremental energy cost, the main consequence of error is the non-optimum use of resources. Consequences might be that fuel would have to be purchased at a premium price or conversely held in inventory; distribution plant might have to be built with overtime labor or conversely labor might be used in projects which could be delayed a year; nuclear or hydro resources might go unused or conversely be used up and substituted for with higher priced fuel.

However, gross inaccuracies in such forecasts could lead to a shortage in available capacity. Because distribution facilities have a minimum planning period of about one year, errors in the short-term forecasts could result in inappropriate distribution construction schedules.

b. Intermediate-Term

Because of the critical role intermediate-term forecasts play, as discussed above, the consequences of error of such forecasts are the most serious.

Forecasts which are too low could result in the use of high-cost resources, heavily-loaded transmission and distribution facilities with associated higher losses and reduced reliability. Low forecasts could also reduce the opportunity for power and energy sales with neighboring utilities and could even result in curtailment of load. Forecasts which are too high, on the other hand, cause problems of equal severity. This could lead to the construction of unneeded generation, transmission and distribution facilities and thus to higher cost electric service.

To convey an impression of the magnitude of the effect of an intermediate-term forecast error and of its ramifications, it is perhaps useful to give a rough estimate of the effects of a specific error—a 10% forecast error in 10 million kilowatt system.

Such an error could result in the demand being one million kilowatts lower than expected with one million kilowatts of generating facilities in operation one year or more ahead of the time required. Assuming for purposes of illustration a plant investment range of \$100–\$150 per KW, and total fixed charges at an annual rate of 15%, the cost due to the forecast error could be \$15 million to \$22.5 million per year. Meanwhile, if the energy forecast were equally in error, the increase expected in revenue would not materialize. Assuming an annual revenue of \$20–\$40 per KW, this could represent an unrealized growth in annual gross revenues of \$20 million to \$40 million.

Of course, there would be some offsetting savings, such as revenue from possible sales of excess power to neighboring utilities, lower system fuel costs resulting from lower energy requirements and from the use of new, more efficient generating facilities to carry the system load and increased flexibility in the maintenance schedule.

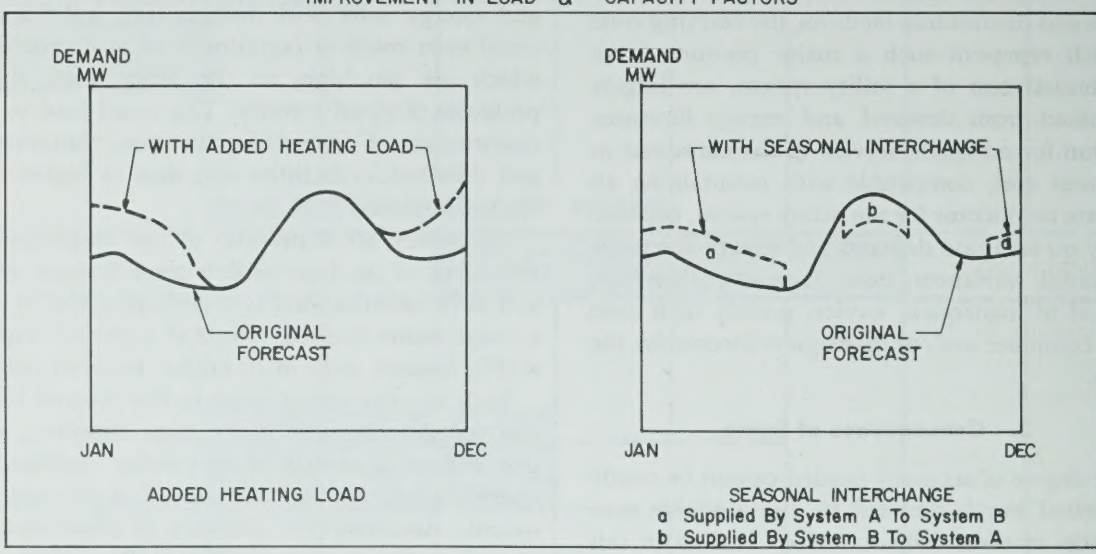
An error of such magnitude in the opposite direction could create a severe risk as to the reliability

of the system. To compensate for this, a system may have several alternatives. For example, if feasible, construction schedules could be speeded at a premium cost, relatively expensive firm power purchased from neighbors or higher operating cost peaking type capacity could be ordered. The full economic cost of any of these alternatives to the consumer, the stockholder or the local economy is difficult to quantify.

c. *Long-Term*

The consequences of error in long-term forecasts are broad in scope and vary widely in accordance with the specific programs developed. While errors could lead to management decisions that in retrospect would appear faulty and take years to correct, some errors may be such that the utility would be able to recover from them with little or no consequence when studying intermediate-term forecasts. For example, long-term contracts or the establishment of special rates commit the utility and thus would preclude any recovery action for the term of the commitment. On the other hand, construction programs that do not require full commitment until the intermediate-term forecasts are made can be adjusted in the intervening years.

FIGURE 3
IMPROVEMENT IN LOAD & CAPACITY FACTORS



BASIC LONG – TERM FORECASTS CAN LEAD TO POLICY DECISIONS TO IMPROVE SYSTEM LOAD FACTOR AND GENERATING PLANT CAPACITY FACTOR

CHAPTER III—CLASSIFICATION AND CHARACTERISTICS OF LOADS

A. Classification

For the purpose of analysis it is often desirable to separate a utility system's total load into smaller components or classes. The nature of the classification depends upon the need of the forecaster and availability of data. Some of the more typical groupings are by type of customer, by type of use, by level of use, by geographic location, by rate schedule and by supply voltage.

1. F.P.C. Classes

The Uniform System of Accounts prescribed for Public Utilities and Licensees by the Federal Power Commission designates the several series of operating revenue accounts as follows:

a. Residential

Residential Sales—". . . for electricity supplied for residential or domestic purposes. Records shall be maintained so that the quantity of electricity sold and the revenue received under each rate schedule shall be readily available."

b. Commercial and Industrial

Commercial and Industrial Sales—". . . for electricity supplied to customers for commercial and industrial purposes. . . Records shall be maintained also so as to show separately the revenues from commercial and industrial customers (a) which have demands generally of 1,000 kw or more, and (b) those which have demands generally less than 1,000 kw . . . If the utility classifies large commercial and industrial customers and related revenues on a lesser basis than 1,000 kilowatts of demand, or segregates industrial customers and related revenues according to a recognized definition of an industrial customer, such classifications are acceptable. . ."

c. Other

Public Street and Highway Lighting—". . . for the purposes of lighting streets, highways, parks and other public places, or for traffic or other signal system service, for municipalities or other divisions or agencies of state or federal governments."

Other Sales to Public Authorities—". . . for electricity supplied to municipalities or divisions or agencies of federal or state governments, under special contracts or agreements or service classifications applicable only to public authorities . . ."

Sales to Railroads and Railways—". . . for electricity supplied to railroads and interurban and street railways for general railroad use, including the propulsion of cars, or locomotives, where such electricity is supplied under separate and distinct rate schedules."

Sales for Resale—". . . for electricity supplied to other electric utilities or to public authorities for resale purposes."

Interdepartmental Sales—". . . for electricity supplied to other utility departments."

d. Problems of Classification

While such classifications appear clear and uncompromising, there are significant differences in reporting among utilities. For example, some utilities treat apartment and mobile home park dwellers as individual residential customers and report all usage as such. Others master-meter the building or park and count it as a commercial account. Some utilities classify all farms as residential customers. Others separate the larger farms and group them with commercial customers.

There have been continuing efforts to further standardize such reporting within the industry. However, significant differences remain, largely because the way in which individual systems use classifications reflect their rate categories and service philosophies.

2. Supplementary Groupings

The preceding classifications, while fairly broad, may suffice in forecast analysis for certain systems. However, variations and subdivisions within this series are as many as the imagination of the fore-

TABLE 4

Sample Customer Classification

Domestic:
Residential
Farm service
Residential—rural
Residential—space heating
Farm service—space heating
Residential—rural—space heating
Commercial
Commercial—space heating
Commercial—rural
Commercial—rural—space heating
Industrial
Industrial—space heating
Public street and highway lighting
Other sales to public authorities
Sales for resale:
Rural electric cooperatives
Other electric utilities

caster deems useful, but care must be taken to match the benefit with the cost of establishing and maintaining the data base. Table 4 is a specific example of customer classification by type of use employed by one system.

Such detailing of classifications may enable the forecaster not only to view the growth trends of particular segments of the market in more detail for load forecasting but also to develop a sales forecast with more precision than afforded through working with the class aggregate.

a. Type of Use

(i) *Location or Type of Dwelling Unit*

Within the residential class customers can be coded on the basis of the location of their residence, that is, in an urban, suburban or rural area. This might be particularly appropriate if farms are generally classified as residential and sales to that group are of sufficient magnitude to be set out separately. Residences might also be classified by type such as single-family dwelling, duplex, apartment, mobile home or seasonal dwelling.

(ii) *Devices*

Another method would be to classify residential customers on the basis of the types of appliances used, such as homes with electric ranges, or with electric water heaters, or electric space heating, or air conditioning or some combination of such appliances.

A similar breakdown might be made for commercial and industrial customers. This might be by those having electric air conditioning, electric heating, process heating, large motor loads, electric cooking, etc.

(iii) *Standard Industrial Classification (SIC)*

Some systems group commercial and industrial customers by SIC codes as established by the Bureau of the Census. This provides detailed categories of electric use by homogeneous groups. Other systems elect to classify these customers only by the broadest categories such as metal related industries, extractive industries, service industries, etc.

Still other systems study in detail only a small number of commercial and industrial customers. These might be the 50 or 100 largest. Their load is then forecast separately from the remaining commercial and industrial accounts.

b. Level of Use

Another possible method of subdividing load for analytical purposes is the separation of customers or groups of customers by volume of use alone. Such subdivision could utilize as size criteria such items as billing demand, amount of energy used or, in some cases, load factor groupings.

One advantage of this type of classification is that the larger units or groups have the greatest impact upon the trend of total demand and analytical effort can be more effectively utilized by concentrating on these groups.

c. Rate Schedules

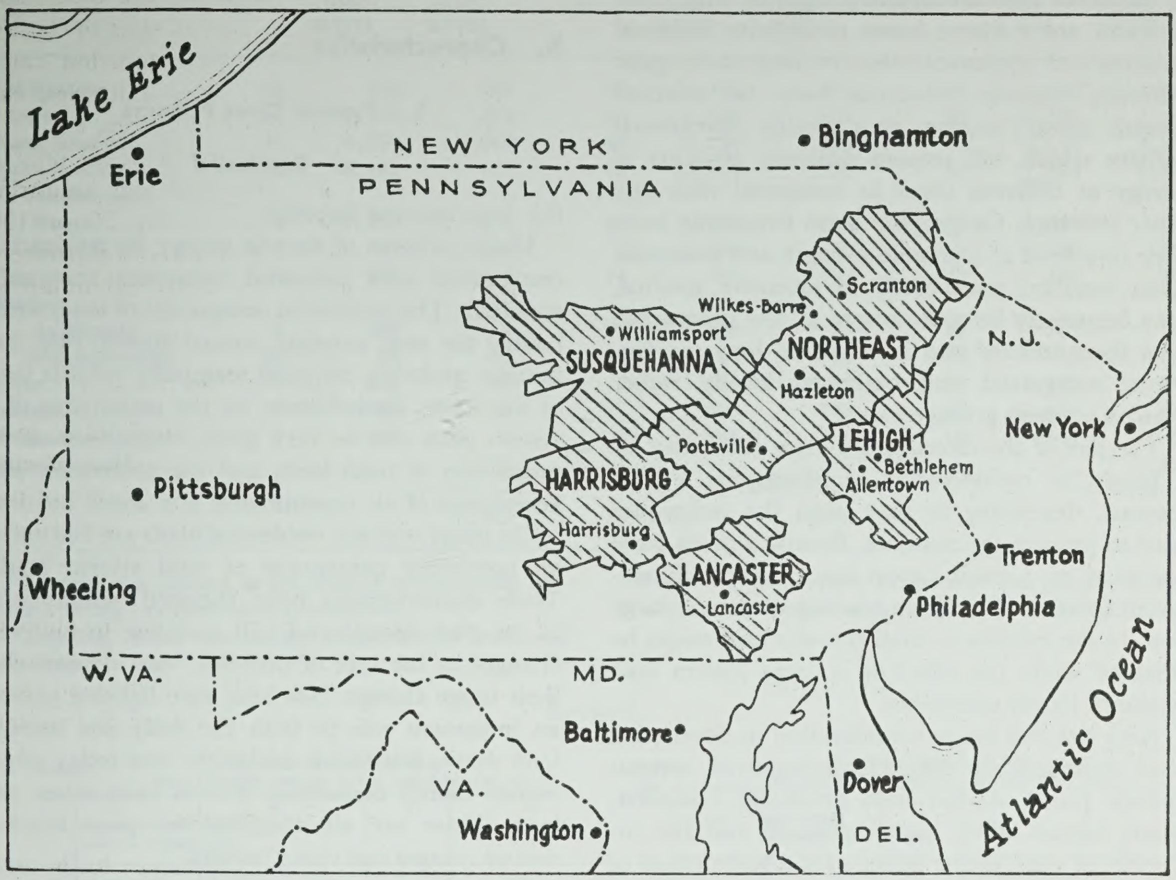
A further classification of customer loads used in forecasting is by rate schedules. This method can provide more detailed variations than the minimum grouping of customers prescribed by the Uniform System of Accounts. Rates are usually designed to be applicable to particular kinds of groupings of customers and therefore lend themselves well to workable classifications for forecasting purposes. The energy data is usually readily available in the regular course of business of a utility. But for forecasting for more than one utility system, care must be taken, since rate classifications frequently differ among utility systems.

d. Geographic Areas

Although it is widespread practice among utility load forecasters to segment their service territories into several subdivisions, there is little uniformity of method. Some select areas by geographic

FIGURE 5

EXAMPLE OF SUB-AREAS IN A SERVICE TERRITORY



THE MAP ABOVE SHOWS THE SERVICE TERRITORY OF PENNSYLVANIA POWER & LIGHT COMPANY AND THE SUB-AREAS USED FOR OPERATING PURPOSES. THESE TYPES OF SUB-AREAS COULD BE USED FOR FORECASTING PURPOSES.

boundaries or municipal subdivisions; others segregate by operating areas or sales areas, or by regions served from major substations; still others specifically define areas by known or expected sales growth rates which may be much higher or lower than the system average. The selection of subareas is usually governed by the availability of historical sales, demand or other data for each area, and by the likelihood of perpetuating and expanding such data.

There are at least two methods by which this can be accomplished. One is to select appropriate feeders or substations supplying the area and measure the power input into the area. Another is to identify the accounts served in the area and periodically summarize billing information.

Subdividing the system geographically facilitates analysis if the sub-areas so selected have unique attributes. Also, specific economic or environmental conditions which influence energy and demand characteristics can, in many instances, be identified and correlated with load changes in each area. Patterns of electrical use in an urban area are in sharp contrast with those in rural areas where hours of activity, seasonal patterns and equipment uses are likely to be quite different. Certain sub-areas may be oriented directly toward tourism or a specific recreational activity which will require different amounts of energy at different times as compared with any other sub-area. Geographic areas frequently have their own level of economic strength and potential. Even weather, particularly in extensive systems, may frequently be more severe in one geographic area than another and its effect on load requirements recognized and evaluated locally rather than on a system average basis.

The size of the forecasting system itself may be a factor for consideration in developing a load forecast, depending in part upon the techniques used to prepare the estimate. Placing a given large customer on a small system has a completely different relative effect from placing him on a large one. In the extreme a small system's load might be doubled while the effect on a large system load would be barely noticeable.

Area size is a major consideration in developing load estimates for large interconnected systems (power pools). As has been previously discussed, many factors affect system demand and the influence of each factor varies over a wide range of values. Those most aware of these effects are the member utilities who have gained a more intimate knowledge of the different characteristics of the area and the effect each has on its own system. They have the statistics and the general knowledge of the area to make the best estimate. Thus, for the more extensive interconnected systems, demand forecasts are usually the resultant sum of independent forecasts made by each participating utility for its own system corrected for the historical diversity that has existed among the various member systems. A related problem pertaining to forecasting by components is discussed in Chapter V Section C.2.

e. *Other*

Another method of classification now used by a number of utilities is to break the total load into two segments, the base load and the weather-sensitive load. Base load is treated as a function of the general state of the economy while the weather-sensitive load is considered to vary with weather conditions. This breakdown differs from the others in that statistical analysis is used to derive the two segments.

B. Characteristics

1. Typical Class Patterns

a. *Residential*

(1) *Importance and Volatility*

Usage patterns of electric energy by residential, commercial and industrial customers vary substantially. The residential component of load, while having the most constant annual growth rate, has become probably the most seasonally volatile load of the three. Its influence on the seasonality of a system peak can be very great, dependent on its proportion of total load, and the promotion and acceptance of air conditioning and space heating.

On many systems, residential loads are becoming an increasing percentage of total system loads. Their characteristics have changed substantially in the past decade and will continue to undergo changes as the mix of domestic load devices and their usage change. Not long ago, lighting played an important role in both the daily and annual load curve, but this is no longer true today when higher energy consuming devices have taken the lead. These are air conditioners, space heating devices, ranges and water heaters.

The refrigerator is one of the most widely-used domestic appliances. Since it operates in an area of almost level temperature and its use is controlled by a thermostat, its diversified use is almost a constant load. Usage of an electric range is generally limited to three periods a day, with the greatest coincidence during the evening period.

Other than space heating and cooling devices, electric water heaters are the largest users of kilowatthours of any domestic appliance today. While their usage characteristics are determined by size of the family, the number of appliances in the home which use hot water, and the ground water temperature, they too are thermostatically controlled and have a highly diversified consumption.

(2) *Standard of Living*

The standard of living has been increasing steadily in the United States, with more leisure

TABLE 8

Sources of Residential Average Annual Use

Electric appliance	1949			1959			1969		
	Saturation (%)	Appliance annual use KWH	Contribution to annual use KWH	Saturation (%)	Appliance annual use KWH	Contribution to annual use KWH	Saturation (%)	Appliance annual use KWH	Contribution to annual use KWH
Refrigerator	69	360	248	97	415	403	98	660	647
Range	31	1,350	419	63	1,350	851	80	1,350	1,080
Water heater	16	4,050	648	44	4,490	1,976	71	5,175	3,674
Space heating	2	8,860	177	18	10,710	1,928	31	11,260	3,491
Air conditioner:[1]									
Room	5	1,250	6	15	1,355	203	36	1,680	605
Central				2	3,500	70	9	4,100	369
Television	1	400	4	74	400	296	99	400	396
Washer:									
Automatic	8	100	8	28	100	28	49	100	49
Nonautomatic	38	50	19	45	50	23	40	50	20
Dryer	4	940	38	9	1,130	102	35	1,335	467
Freezer	7	895	63	21	900	189	38	980	372
Dishwasher	1	325	3	5	285	14	16	340	54
Miscellaneous[2]			1,132			1,323			2,376
			2,765			7,406			13,600

[1] Saturation is defined as the percent of residential customers having 1 or more room conditioners.

[2] Lighting, small appliances, supplemental heat and other uses.

Note: The table shows the pattern and growth in residential average annual use for a system in Southeast.

FIGURE 6

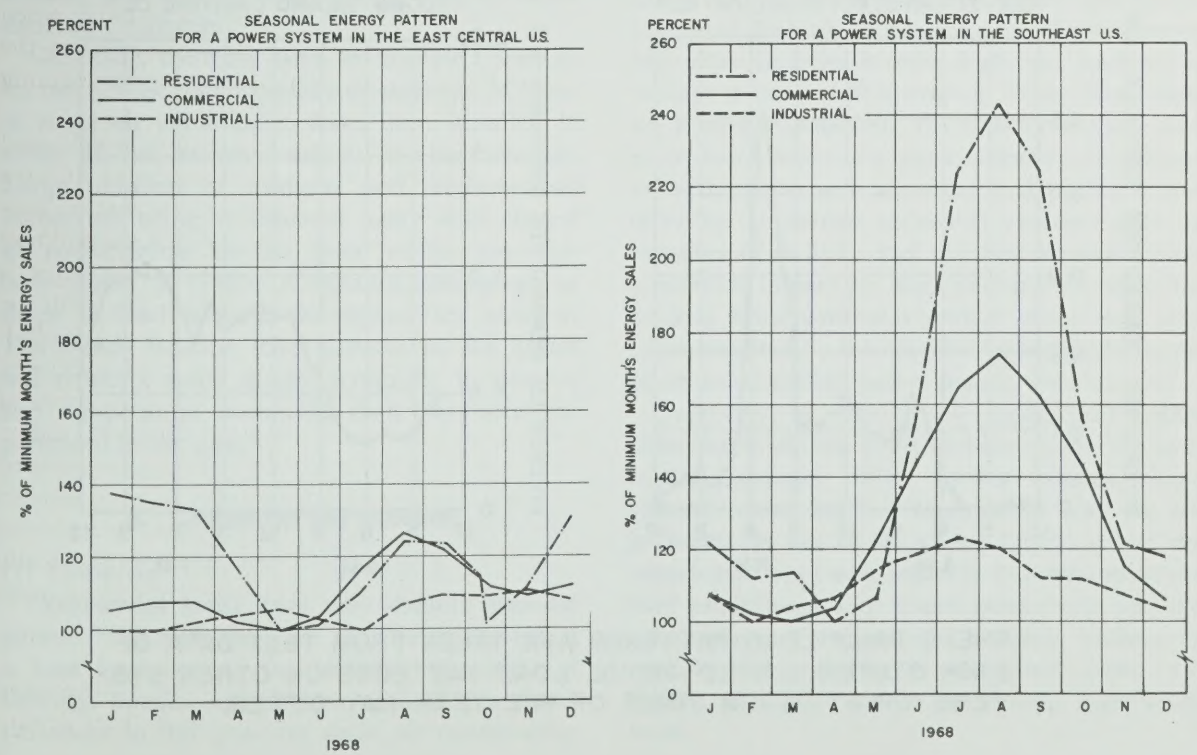
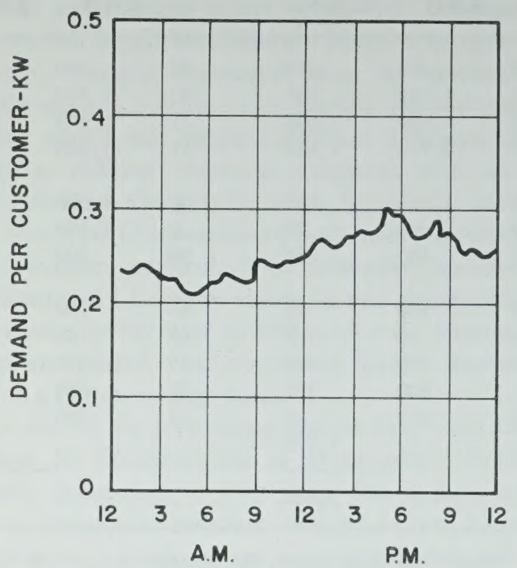


FIGURE 7

DAILY LOAD PATTERNS
SELECTED RESIDENTIAL APPLIANCES

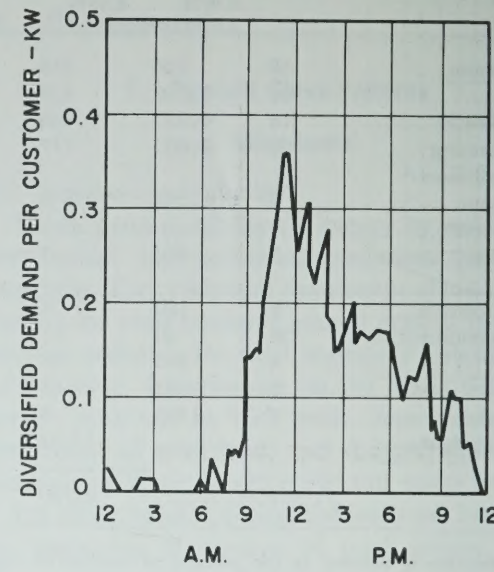
FROST-FREE REFRIGERATOR FREEZER
SUMMER WEEKDAY

(BALTIMORE GAS & ELECTRIC CO.)



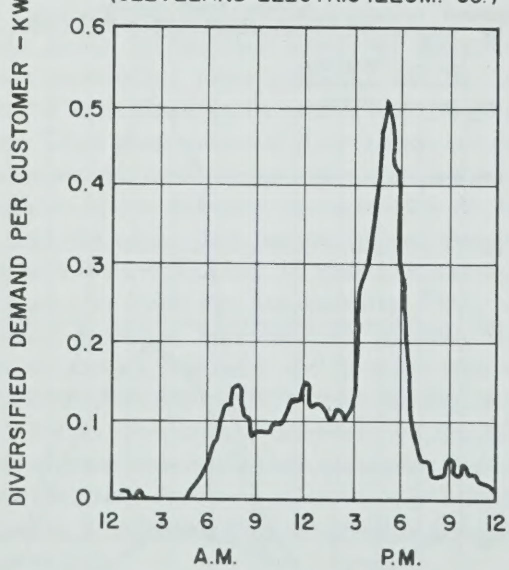
DRYER
WINTER WEEKDAY

(CLEVELAND ELECTRIC ILLUM. CO.)



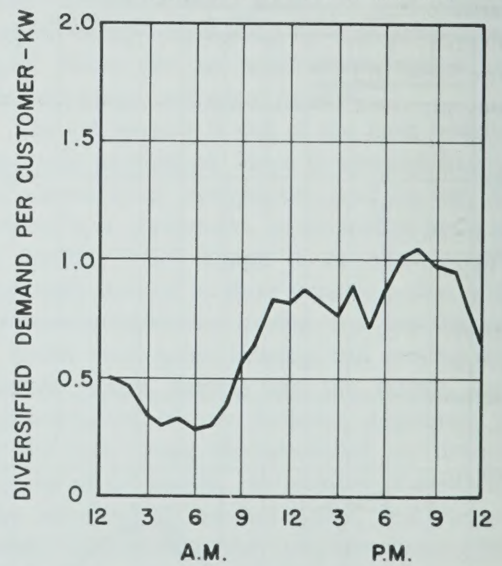
RANGE
WINTER WEEKDAY

(CLEVELAND ELECTRIC ILLUM. CO.)



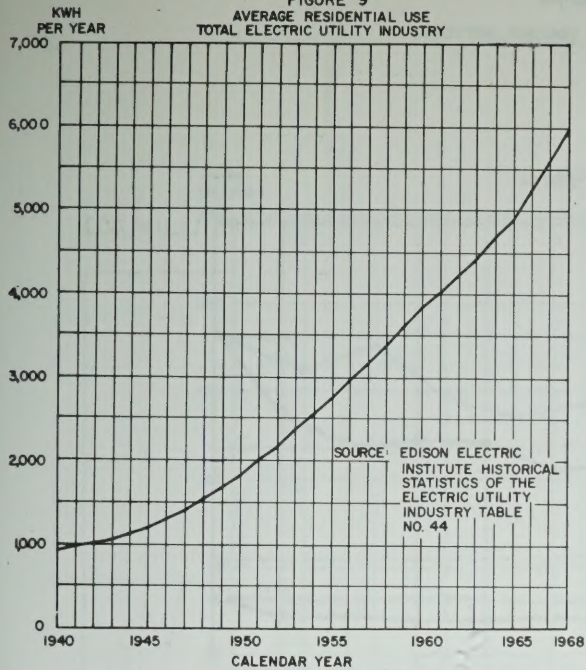
WATER HEATER
WINTER WEEKDAY

(LONG ISLAND LIGHTING CO.)



THESE DAILY LOAD PATTERNS ARE TAKEN FROM TEST DATA OF EACH SYSTEM LISTED ABOVE. LOAD PATTERNS ON OTHER SYSTEMS OR AT OTHER TIMES OF THE YEAR MAY DIFFER.

FIGURE 9
AVERAGE RESIDENTIAL USE
TOTAL ELECTRIC UTILITY INDUSTRY



ONE MEASURE OF INCREASING AFFLUENCE IS THE INCREASED USE OF ELECTRICITY BY THE AVERAGE RESIDENTIAL CUSTOMER.

time as a natural by-product. The additional leisure has resulted in increasing the use of electrical devices for recreational purposes, such as television, radio and woodworking tools. Higher incomes have led to higher standards of home lighting and more lighting is being used for home decorative purposes.

Generally, there has been an increased demand for more home comforts and conveniences. Millions of room air conditioners have been installed in areas of the country subject to hot weather. Large numbers of medium and higher-priced homes are being constructed today with central air conditioning. Electric space heating has similarly begun to obtain acceptance, changing the shape of load patterns throughout the country. The trends indicate load patterns in the future will reflect a much greater sensitivity to weather and temperature variations than has been experienced in the past.

b. Commercial and Industrial

(1) *Commercial*

Commercial loads have very definite seasonal patterns although they are sometimes treated as a base load due to the historic importance of lighting. Specific applications producing seasonal variations in this class are again air conditioning and space heating. In areas of high saturation, the seasonal effect of air conditioning on load patterns has already been felt. In the remaining areas, small stores, filling stations and many schools will either rapidly adopt air conditioning or will become a small portion of the total commercial load.

Electric space heating is beginning to be accepted in commercial applications. The effect of "heat-with-light" applications on seasonal load patterns may be slight, since the load is dominated by high level lighting which can substitute in part or in whole as the heat source. Other electric heating applications, however, will have a substantial effect on seasonal load patterns.

(2) *Industrial*

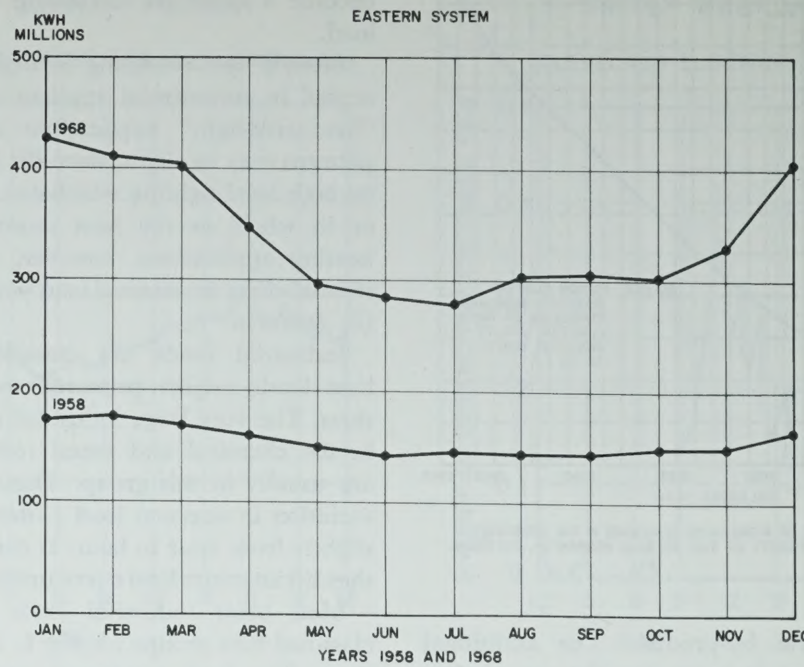
Industrial loads are classified frequently as base loads subject primarily to economic variations. The very large industrial loads, particularly in the chemical and metal reduction categories, are usually in this group. These loads have little variation in seasonal load patterns and vary only slightly from hour to hour. It can be assumed that they lift an entire load curve uniformly.

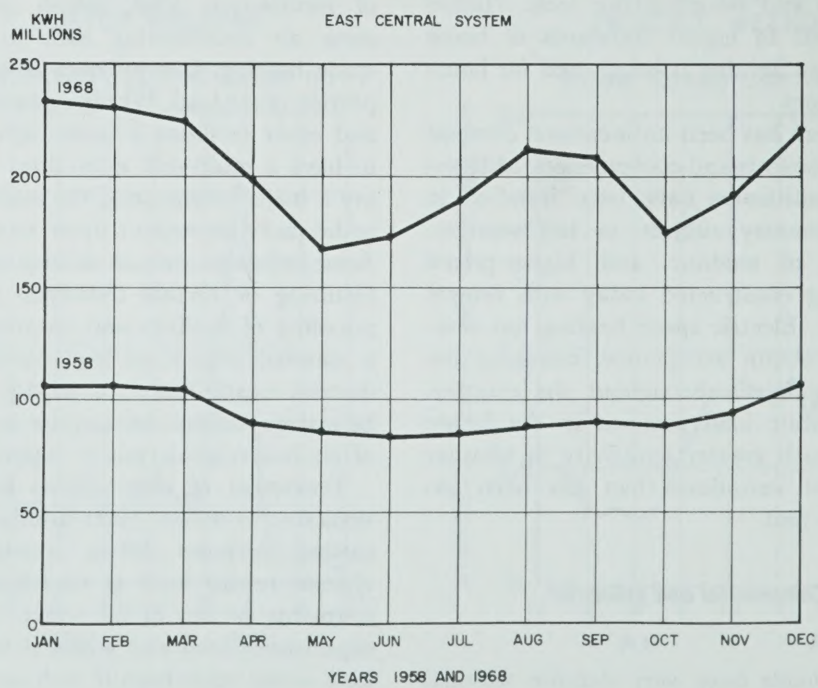
Most other industrial loads may be usefully classified into groups having 1, 2 or 3-shift operations. The load pattern of each is distinctively related to the hours of operation. A certain amount of service-type load, which generally includes some air conditioning and, in some instances, space heating, is supplemental to the production portion of the load. Where investment in machinery and other facilities is quite high, the tendency is to have a multi-shift operation. When labor costs are a major component, the number of shifts tend to be more dependent upon economic conditions. Some industries such as mining and cement manufacturing or certain industrial practices such as retooling of facilities and vacation schedules have a seasonal impact on load patterns. In some industrial establishments a portion of the load may be interrupted by the supplier under special terms of an interruptible power supply contract.

Treatment of interruptible loads, load reductions due to strikes, plant shutdowns, etc. for forecasting purposes differs among systems. Some systems record load as experienced with no adjustments for any of the above. Others record the experienced load and adjust it to reflect what the load would have been if such occurrences had not taken place. Forecasts can similarly include or exclude the possibility of coincident strikes, vacations or reductions by voluntarily interrupted loads.

FIGURE 10

RESIDENTIAL CLIMATE CONTROL PATTERNS

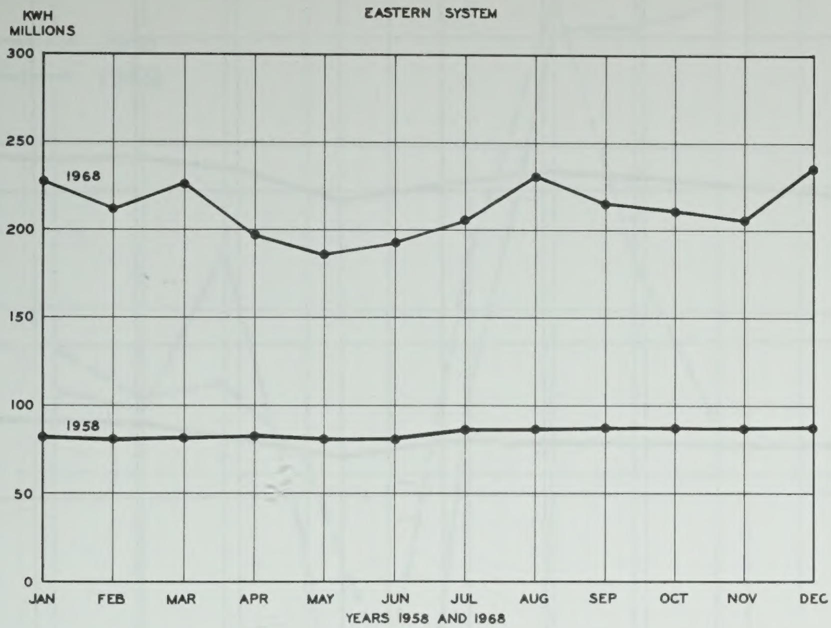


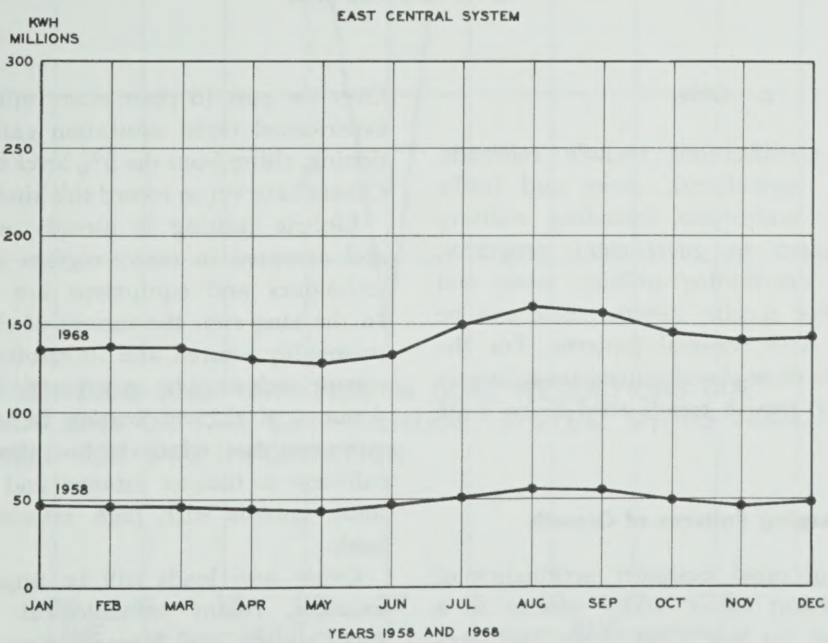


THE CHANGING SEASONAL PATTERN OF RESIDENTIAL USE REFLECTING THE UTILIZATION OF CLIMATE CONTROL DEVICES IS CLEARLY SHOWN.

FIGURE II

COMMERCIAL LOAD PATTERNS

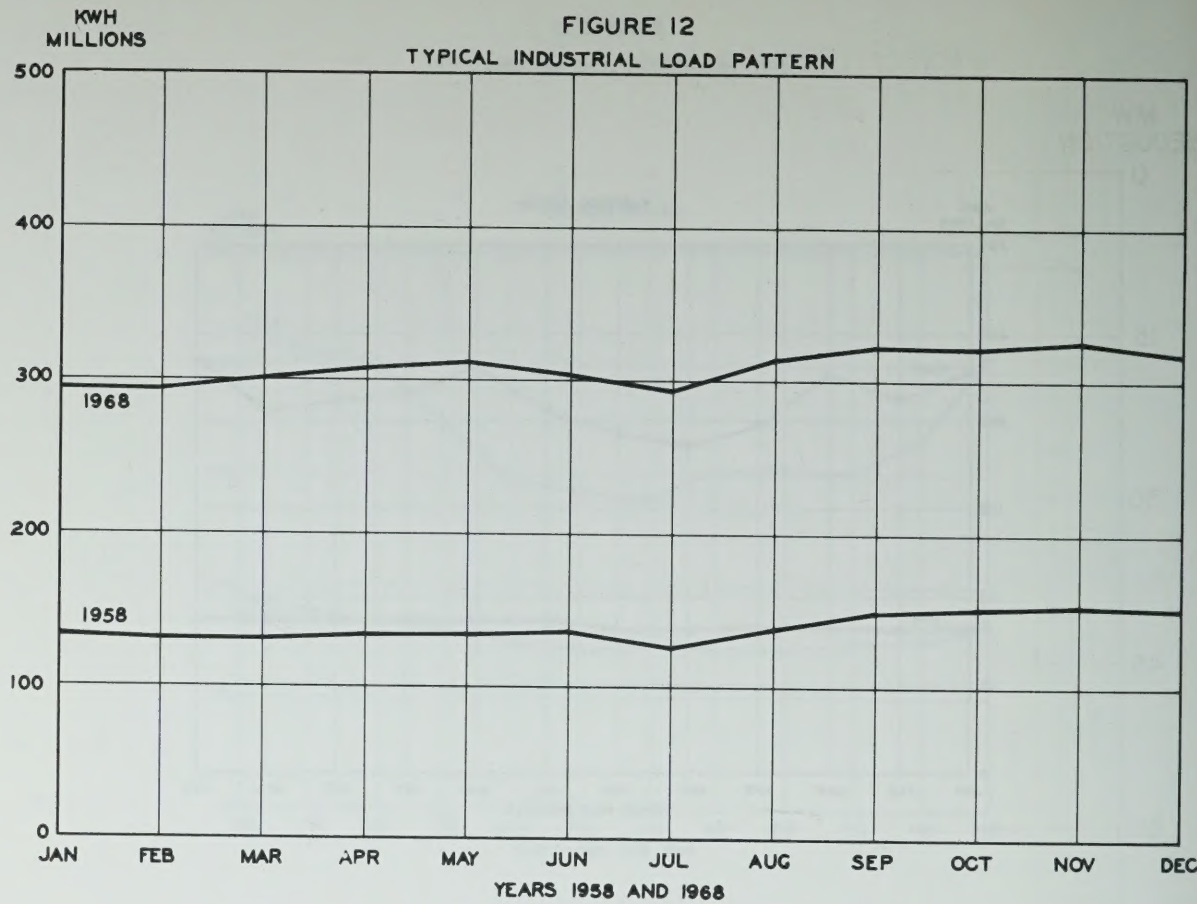




BOTH THE VERY SUBSTANTIAL INCREASE IN VOLUME AND THE DIFFERENCE IN SEASONAL PATTERN ARE EVIDENT IN THIS CHART.

FIGURE 12

TYPICAL INDUSTRIAL LOAD PATTERN



c. *Other*

Other load classifications include railroads, street railways, agricultural, street and traffic lighting, public authorities including military installations related to government programs, resale to other distributing utilities, losses and company use. For specific systems these can be significant and have seasonal patterns. For the nation as a whole these classifications are relatively minor, and their growth trends tend to be quite stable.

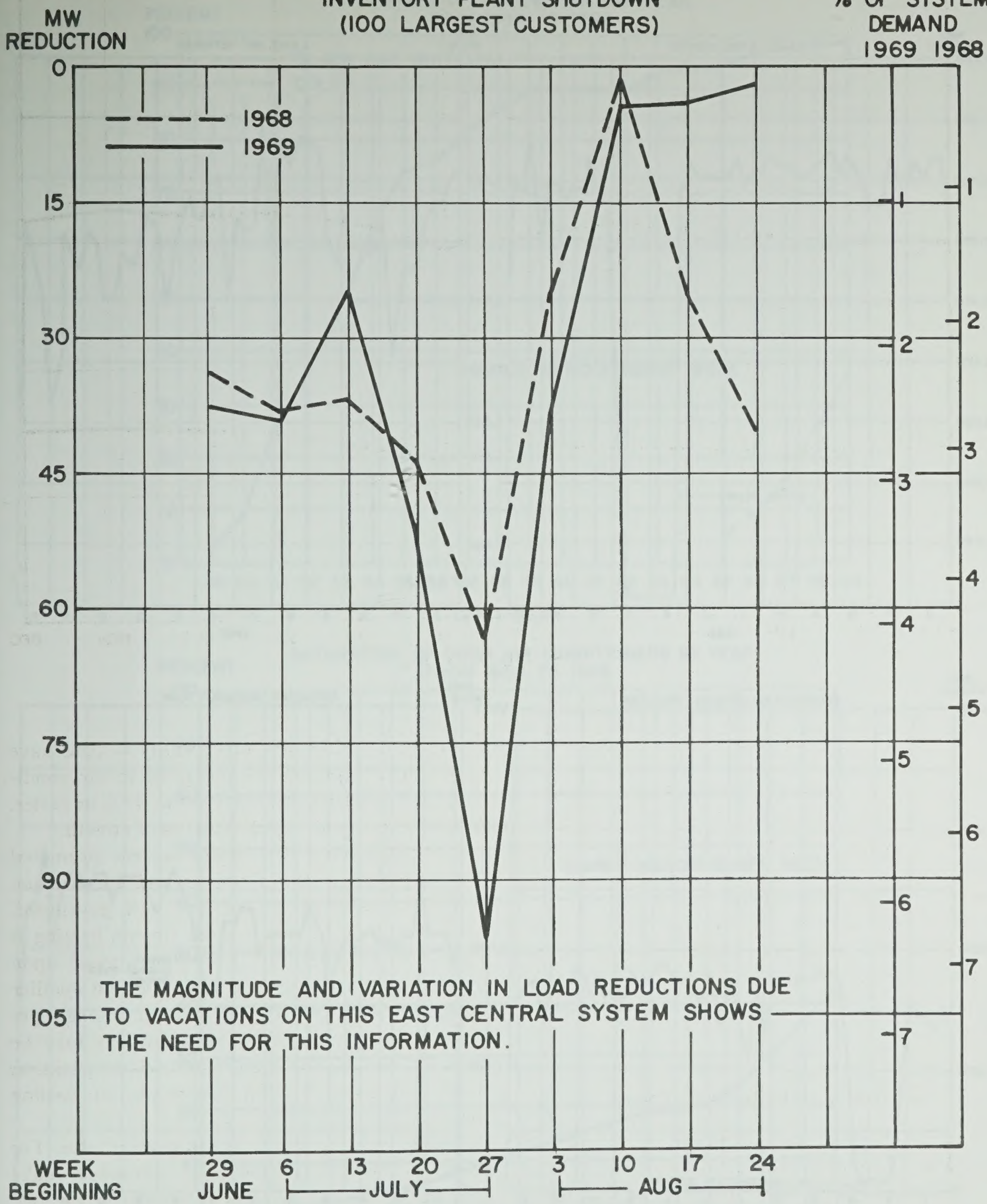
2. Emerging Patterns of Growth

The impact of rapid customer acceptance of electrical equipment on a utility system is a phenomenon that has long plagued the load forecaster. As an example, the television set met with dramatic acceptance upon its introduction in the late 40's, gaining wide acceptance in less than five years. More recently it has been the market for air conditioning in both the residential and commercial markets which is rapidly expanding. Over the past 15 years many utility systems have experienced rapid saturation gains in air conditioning, rising from the 5% level to 60% or better. Others have yet to record this kind of growth.

Electric heating is already widely promoted and accepted in many regions and construction techniques and equipment are well developed. In the long run, the success of electric heating is reasonably assured and its resultant impact upon system loads must be anticipated. The cold weather demand of electric heating is large enough per customer that relatively low saturations may be sufficient to balance summer and winter peaks on some systems with high saturations of cooling loads.

Other new loads will be important also. For example, recent technological advances make small electric steel furnaces economically feasible. Other forms of industrial electrical process heating are making rapid strides. Commercial electric space heating is likely to follow the trends of the residential market. Rapid urban transit powered by electricity may begin to grow rapidly in some utility areas within the next few years. The electric

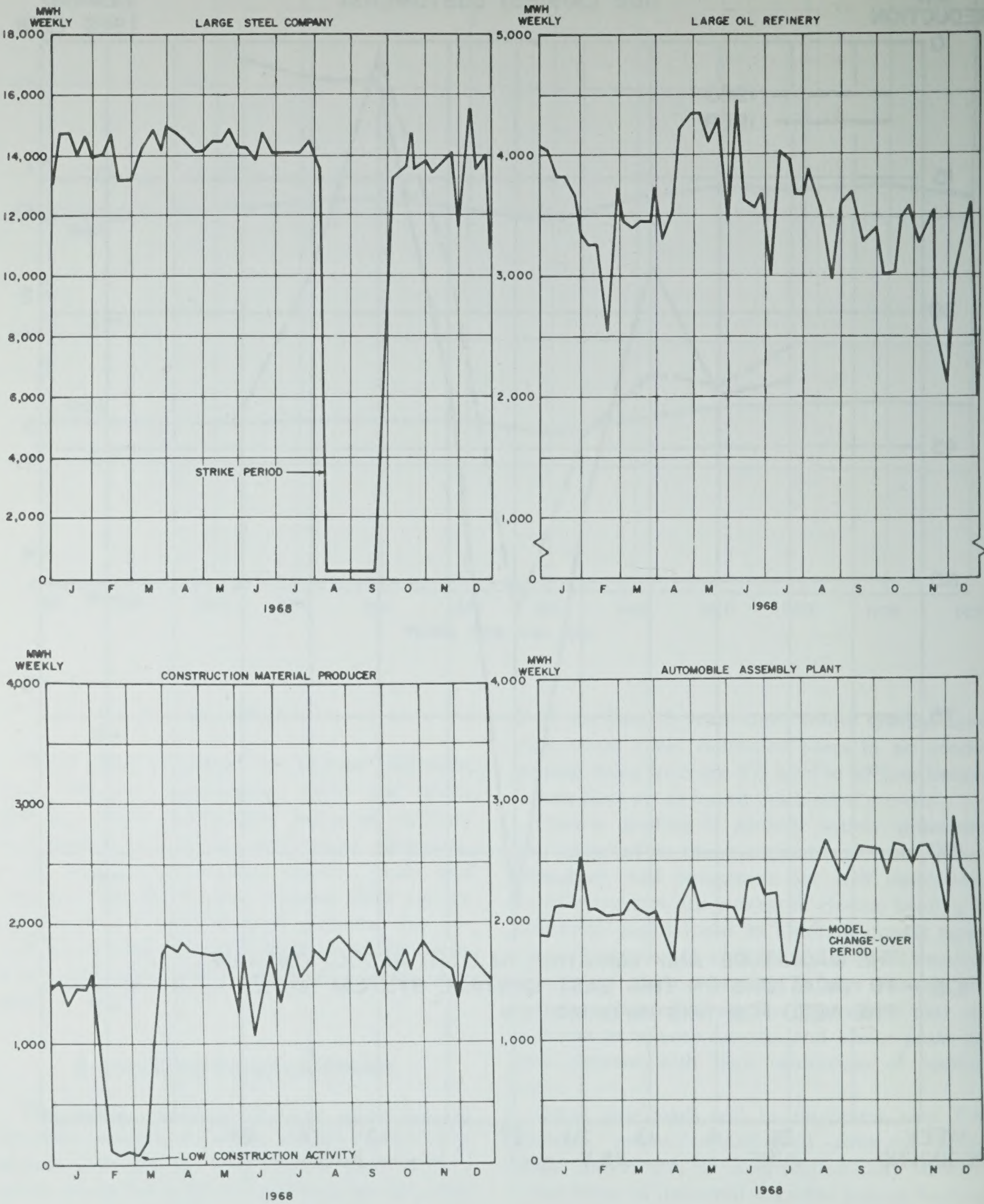
FIGURE 13
PROJECTED LOAD REDUCTIONS DUE TO VACATION AND INVENTORY PLANT SHUTDOWN
(100 LARGEST CUSTOMERS)



automobile may in time have a significant effect upon utility load characteristics, especially if it is developed as an off-peak load. Electrically operated industrial lift trucks also hold a high promise of acceptance. In addition, the future impact of appliances which have already gained a large degree of acceptance should not be overlooked. Among these are the clothes dryer with a national saturation of less than 40% today, and the dishwasher with a 21% saturation.

FIGURE 14

LOAD PATTERNS OF LARGE CUSTOMERS

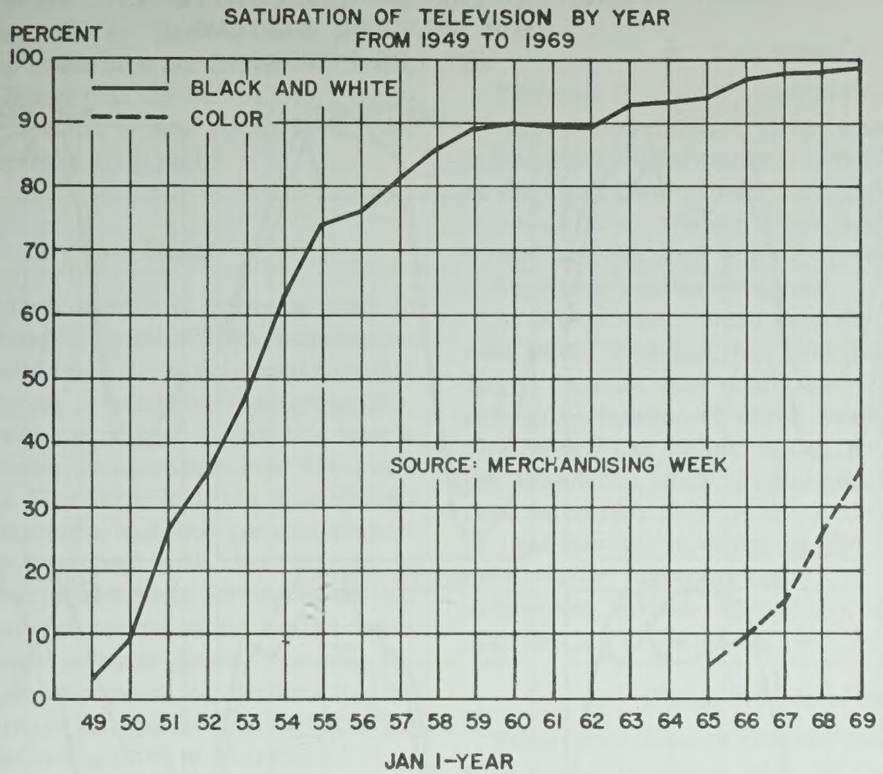


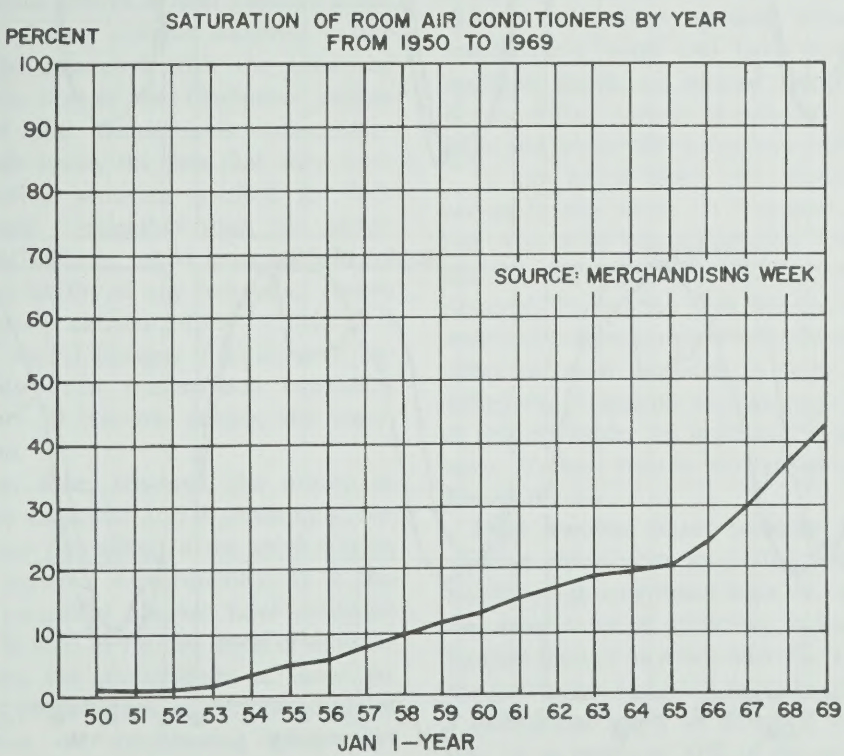
3. Load Responses to Weather

The effects of weather on system loads cannot be overemphasized. Currently most system peak demands essentially result from seasonal weather extremes.

Usually a build-up in daily peaks will occur between the initial peak at the inception of a spell

FIGURE 15

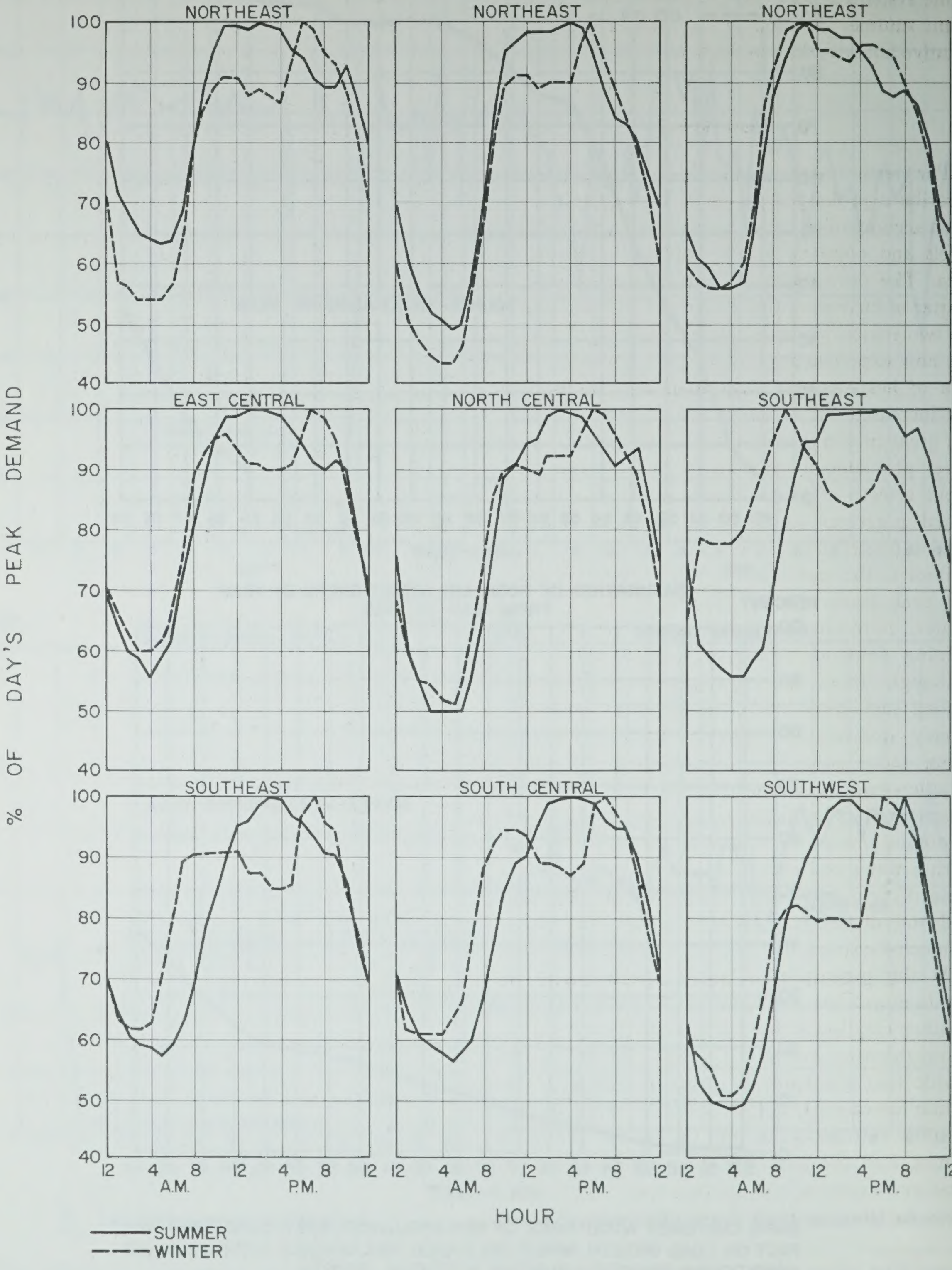




RAPID CUSTOMER ACCEPTANCE OF NEW APPLIANCES HAS A SIGNIFICANT IMPACT ON LOAD GROWTH. WHILE TELEVISION HAS REACHED SATURATION, AIR CONDITIONING PRESENTS FURTHER POTENTIAL GROWTH.

FIGURE 16

1968-69 PEAK DAY LOAD PATTERNS FOR SELECTED SYSTEMS (BY FPC REGION)



of extreme weather and the final high peak load of the period at the end of a number of days of such continuing weather. Each system's pattern of load build-up under these conditions is different. Some systems report that the build-up to a maximum summer demand is now taking fewer consecutive hot days than in the past.

a. Heat Storms

The term "heat storm" is generally used to describe a prolonged period of high temperatures often accompanied by higher than normal humidity levels and covering a relatively wide geographic area. The occurrence of heat storms has been a matter of increasing significance to load forecasters for two reasons. First is the fact that most systems are now experiencing a high and growing proportion of heat-sensitive load such that, in spite of the increased use of electricity for space heating, the great majority of systems in the United States have pronounced summer peaks. Second, the rapid growth of inter-system connections has resulted in greater use of capacity from neighboring systems for assistance at times of emergency.[1]

Prior to the rapid growth of heat sensitive loads, the peak loads of most systems occurred in the winter, normally associated with the increased lighting demands during the Christmas season. Although there was considerable coincidence among such peak loads, the fact that they were largely non-weather sensitive resulted in their being more easily predictable than the highly weather-sensitive summer peaks currently being experienced. The ability of any individual system to obtain emergency assistance from its neighbors during times of forced outages of equipment depended primarily upon transmission capability and the diversity of hazards among the interconnected systems.

At the present time, however, the ability to obtain emergency assistance also depends upon the weather conditions prevailing in the service areas of neighboring systems. Consequently, it is desirable that the capacity planner have available to him forecasts of load at various levels of summer weather extremes, the probabilities of those extremes, and the probabilities of various levels of weather extremes on neighboring geographic areas together with the probable coincidence of such extremes with the various levels of weather extremes on his own system.

b. Cold Waves

This term is generally used to describe a period of time when ambient temperatures are at or below winter temperatures normally experienced in the area. Wind velocity can be combined with temperature to produce what is called a "chill factor" and can serve as a measurement to further define winter weather conditions.

At present the concern over the occurrence of cold waves is far less than that over heat storms largely because only relatively few systems have sufficient saturation of winter weather related devices which can induce system peaks. Thus far, the cumulative effect of continuing cold weather does not appear to be as important as in the case of heat storms. However, as the importance of cold weather load grows, the load predictions by neighboring systems increasingly affect capacity planning just as discussed under "Heat Storms".

c. Change in Seasonal Peak

Energy and demand patterns generally change from season to season. Most of the changes are directly related to weather influences, such as temperature, wind and light conditions. In the southern states, an annual system peak usually occurs during periods of extremely high temperatures and is generally a daytime peak.

In the states where the annual system peak occurs in the winter, it frequently occurs in the late afternoon when darkness, low temperatures and Christmas lighting combine to create a peak demand. In systems with heating loads, darkness and low temperatures usually have enough of an effect to cause the peak to occur in January or February. In systems with an even greater amount of heating loads, the peak may shift to a morning hour. Various system load patterns are shown in Figure 16.

Most systems must consider these kinds of weather effects when analyzing their peaks. Variation in weather extremes from that used in the forecast may cause a difference between actual and forecast load of as much as 15%. In a few systems the maximum variation in daily peak load during a month due solely to differing weather response may be as much as 50% of the annual peak load.

Heating degree days range from about 100 at Key West, Florida to over 10,000 at the Canadian border. Cooling degree days range from less than 100 in the Northwest to over 4400 in the lower

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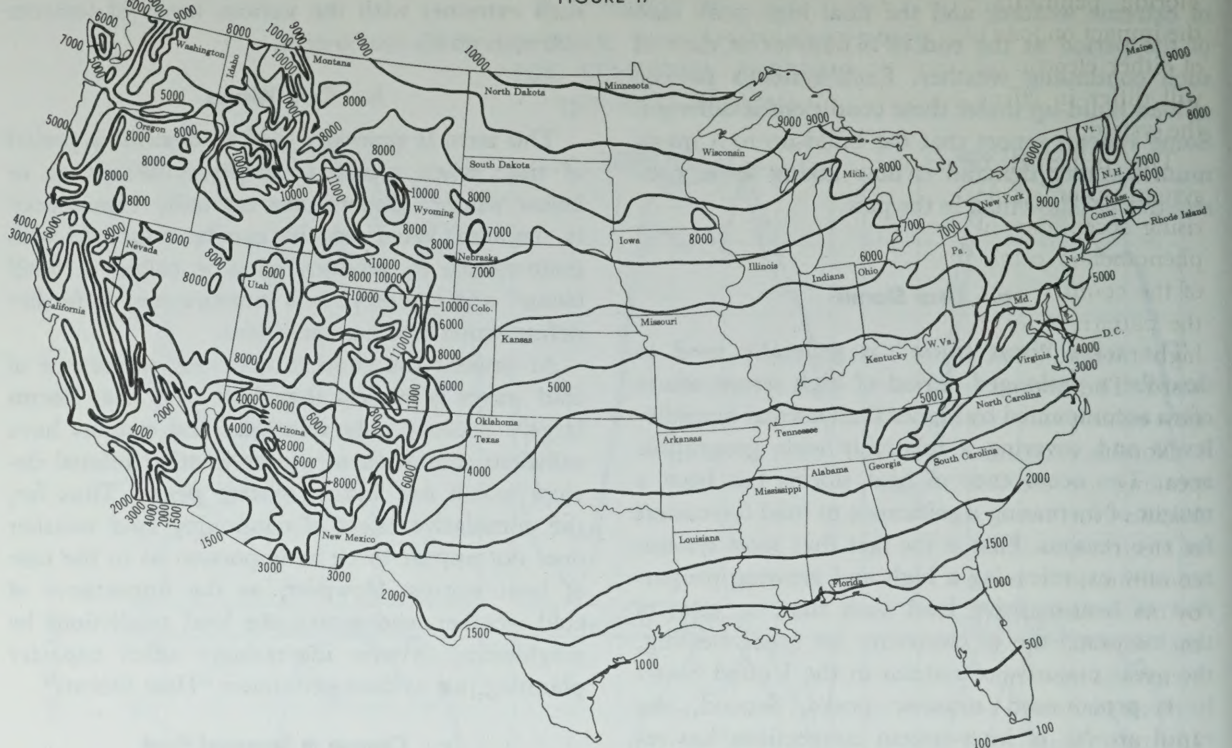
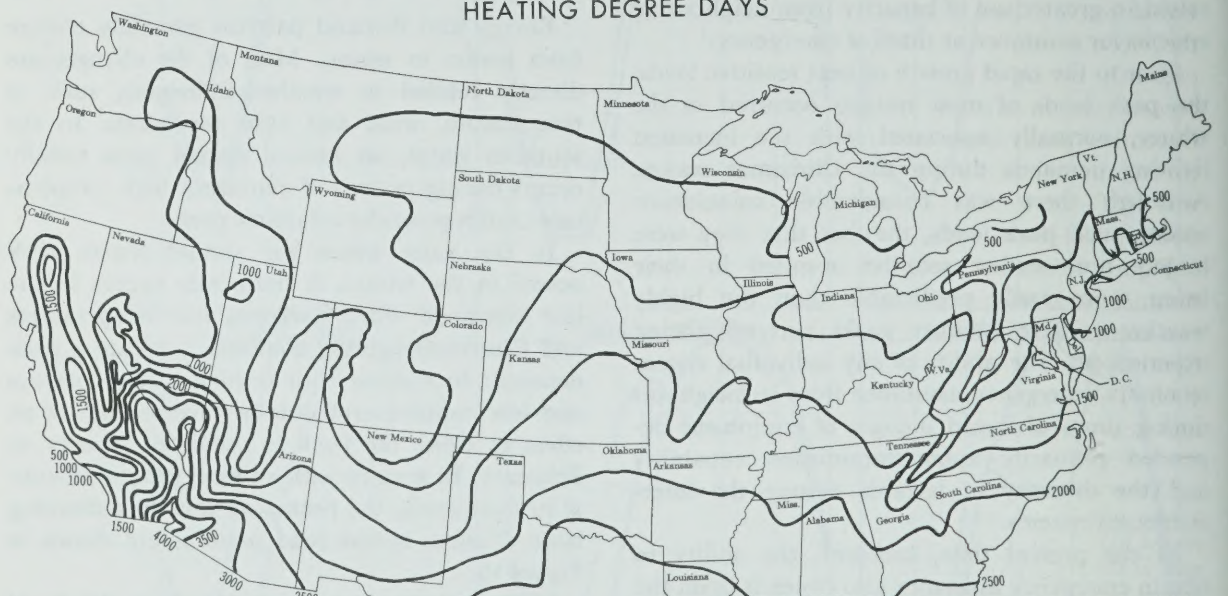
[1] Mutual emergency service is generally grounded upon bi-lateral or multi-lateral contractual agreements.

FIGURE 17



HEATING DEGREE DAYS



COOLING DEGREE DAYS

AVERAGE PER YEAR 1931–1960, BASE: 65 DEGREES

SOURCE: ENVIRONMENTAL SCIENCE SERVICES ADMINISTRATION

Florida peninsula.[2] (See Figure 17.) Therefore, the impact on load of a given percentage saturation of either electric air conditioning or space heating will differ in effect depending on the latitude of the system.

The principal element in the trend toward system summer peaking has been the public's rising acceptance of electric air conditioning. This phenomenon originated in the southern portions of the country over 15 years ago. Since that time the pattern of acceptance has been at a relatively high rate and has steadily worked its way northward. The annual load patterns in many systems now exhibit valleys occurring in the spring and fall.

Notable exceptions to this trend toward summer peaking are the TVA system and systems in the Pacific Northwest. In these areas the saturation of electric space heating is creating winter peaking conditions. Electric heat is being promoted actively by many systems and rising acceptance will change the seasonal load patterns, especially for those systems in more northern latitudes.

Peak load data assembled by the Edison Electric Institute in its April 1969 Semi-Annual Electric Power Survey show that the sum of peak loads of the electric utility industry in the United States presently occurs in the summer. These have exceeded the maximum levels of the subsequent December peaks since 1964.[3] The relationship between summer and the following December peak was 105% in 1968. It is predicted that this relationship will rise to 108% by 1974.

Figure 18 shows the trend of the ratio of the summer peak to the following December peak for two contrasting regions of the country. The South Central (FPC Region V) had a ratio of 1.43 in 1968. This region is characterized by hot summers and heavy irrigation loads. By contrast, the Northwest (FPC Region VII) had a 0.72 ratio in the same year. This region is characterized by cool summers and a relatively high saturation of electric heating.

Figure 19 shows the summer peak as a ratio of the following winter peak for an operating system in the Southeast (FPC Region III). These ratios are plotted against the ratio of the summer peak to the April peak of the same year. The load in April was used to approximate the base load exclusive of weather related loads. This latter ratio shows the relative growth of summer cooling loads and indicates a shift to a summer peak in the early 1950's.

Figures 20 and 21 show the relative growth of summer and winter peaks for two small systems in the Southeast. Figure 20 indicates the change from summer to winter peaks as electric heating saturations reached about 9%. The winter to summer peak ratio continued to increase as the saturation of electric space heating increased. The peak for the system shown in Figure 21 shifted from summer to winter when the saturation of electric heating reached 6%. However, the winter-summer ratio had declined steadily after 1962 because cooling loads had grown faster than heating loads.

One aspect of seasonal peak shifting relates to load diversity. The reader is directed to a publication of the Edison Electric Institute (December 1968) entitled *Report on Load Diversity* from which the following is quoted:

> ...This [load forecast deviation] is an extremely important factor because the degree of certainty as to the difference between seasonal peak loads on a system (which to a large extent is a measure of how much long-term capacity a system can exchange on a diversified basis with another system) is not of the same order of magnitude as the ability of the system to predict its seasonal loads. For example, assume a system can predict its long-range seasonal loads with an accuracy of ±5% and predicts a 10% difference between summer and winter loads. This difference has an associated uncertainty of ±95%* provided there is statistical independence. Of course, if several systems are participating in the diversity exchange, the deviation of the load forecasting errors may lessen the impact; but nevertheless it is an important factor.
>
> *EXAMPLE: Consider a system which forecasts a summer peak load of 1,000 Mw and a winter peak load of 900 Mw resulting in [a] difference between seasonal peak loads of 10%. With a forecast accuracy of ±5% the summer

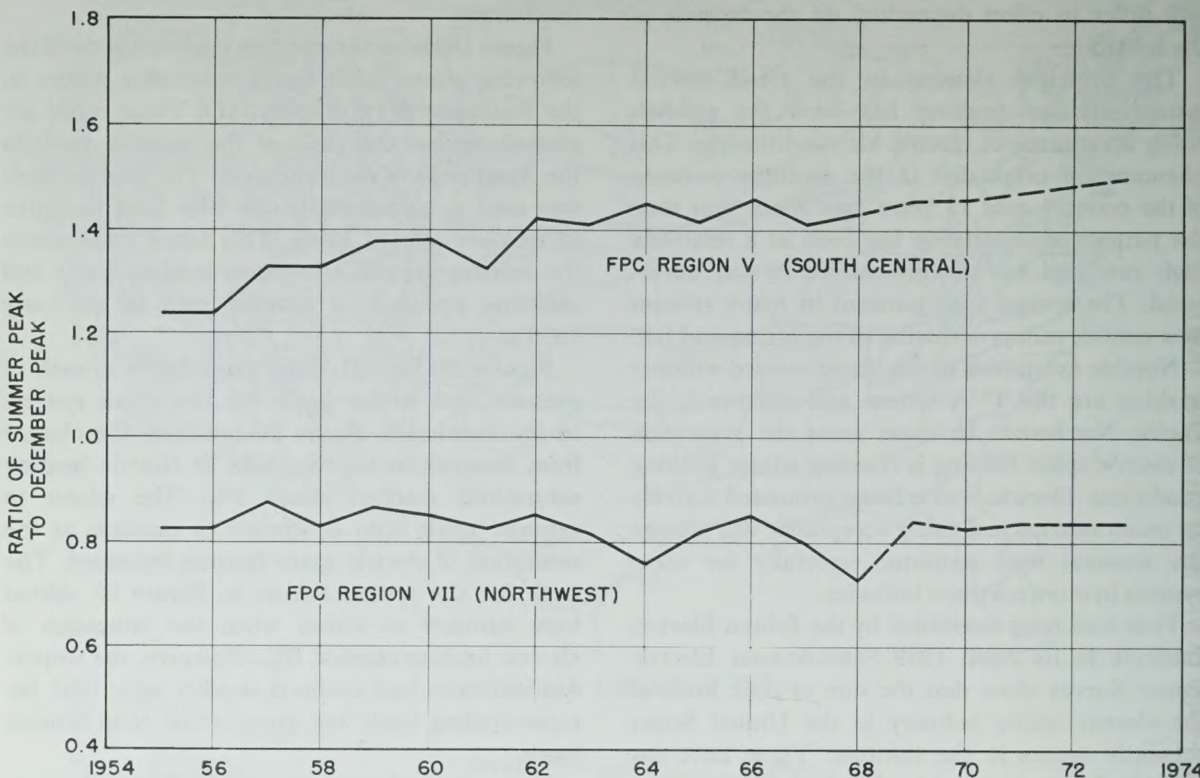
[2] These heating and cooling degree days are derived on a base of 65° and are the average annual data for the period 1931–1960. These data are available from ESSA for each of the 300 reporting stations not only for the average annual period but as well for each month and for different temperature bases. Cooling degree data and heating degree data on a base other than 65° have not been published but are available for the cost of extraction from ESSA tapes.

[3] The semi-annual surveys of the Edison Electric Institute indicate that most of the larger utility systems in the United States normally have their winter peak loads in December.

FIGURE 18

RATIO OF SUMMER PEAK TO FOLLOWING DECEMBER PEAK

FPC POWER REGIONS V AND VII



peak may be anywhere from 950 Mw to 1,050 Mw and the winter peak anywhere from 855 Mw to 945 Mw. If the summer peak should be 950 Mw and the winter peak load 945 Mw, the difference between the seasonal peak loads would be only 5 Mw; rather than the predicted 100 Mw. Conversely, if the summer peak should be 1,050 Mw and the winter peak 855 Mw, the difference between the seasonal peak loads would be 195 Mw. In other words, under the conditions suggested the difference between the seasonal peak loads could be anywhere from 95 Mw under or 95 Mw over the predicted difference of 100 Mw. Thus, the uncertainty associated with the difference is ±95%.

4. Economic and Demographic Effects

In forecasting it is desirable to distinguish between several patterns: seasonal fluctuations, business cycles, long-term growth and irregular events. Each of these will affect different types of industries and different firms to a varying degree. Most irregular events will have only a modest effect on a national scale, but can have a substantial effect locally. For example, an industry oriented to markets abroad is much more likely to be affected by changes in foreign tariffs than is an industry supplying the domestic market.

The electric utility industry as a whole is fortunate to have a regular pattern of long-term growth and is relatively insulated from cyclical variations in the economy. For those systems having a large industrial component which is closely linked to the economy, this will be less true.

Demographic effects on electrical loads are reflected in each of the forecasting time-spans. Significant migration signals quick changes in demand. Major changes in birth or death rates alter the population age structure and have a significant effect on energy consumption. Also, this will affect the trend of household growth many years into the future. About 20 years after birth, individuals tend to become new utility customers.

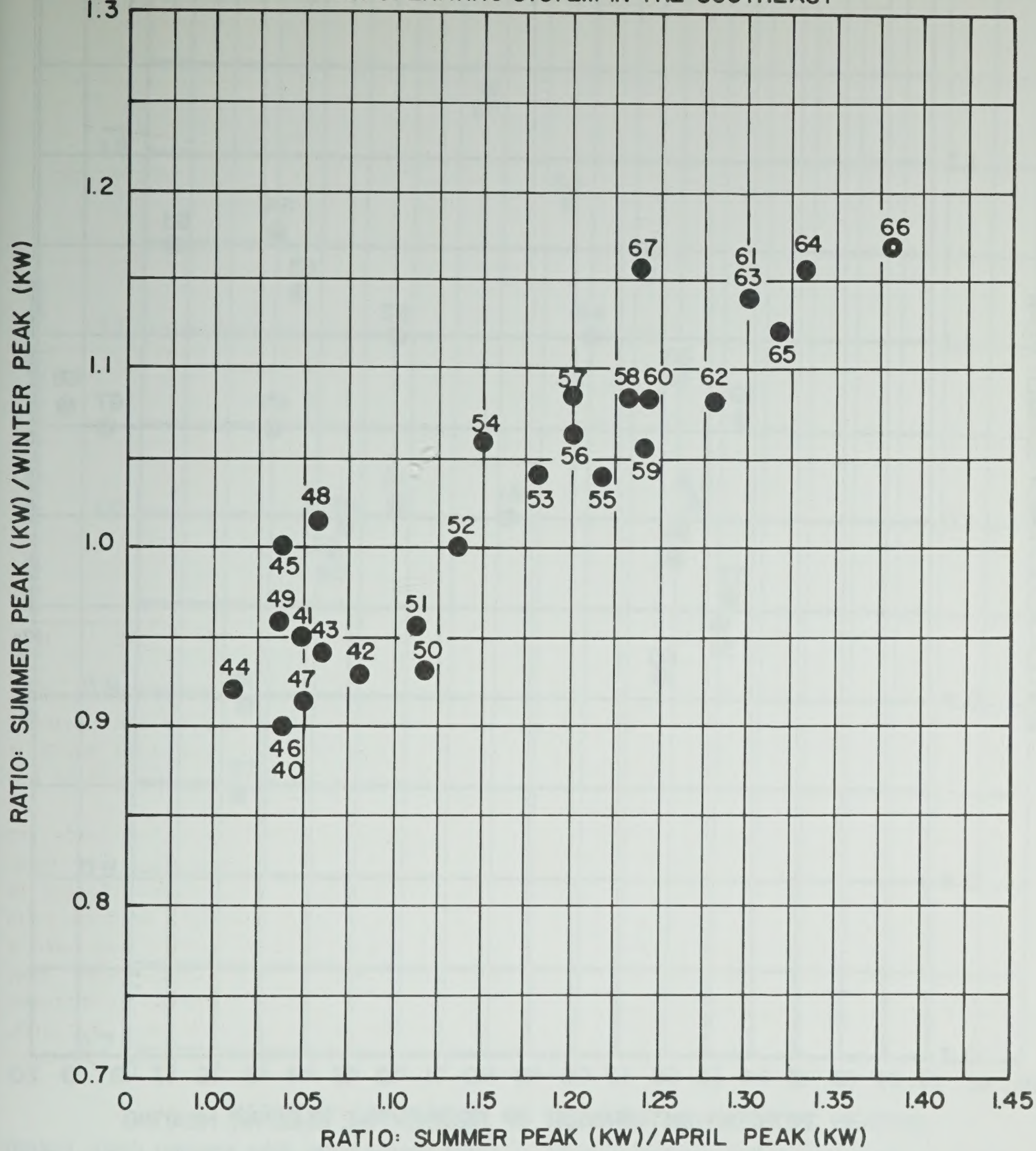
5. Marketing Policy Effects

So far load characteristics have been dealt with as if the utility had no control over emerging patterns. There are, however, many ways in which the utility can help shape the changes taking place in its service territory.

a. Promotion

Promotional effects on load can be divided into two types: short-term and long-term. Most systems

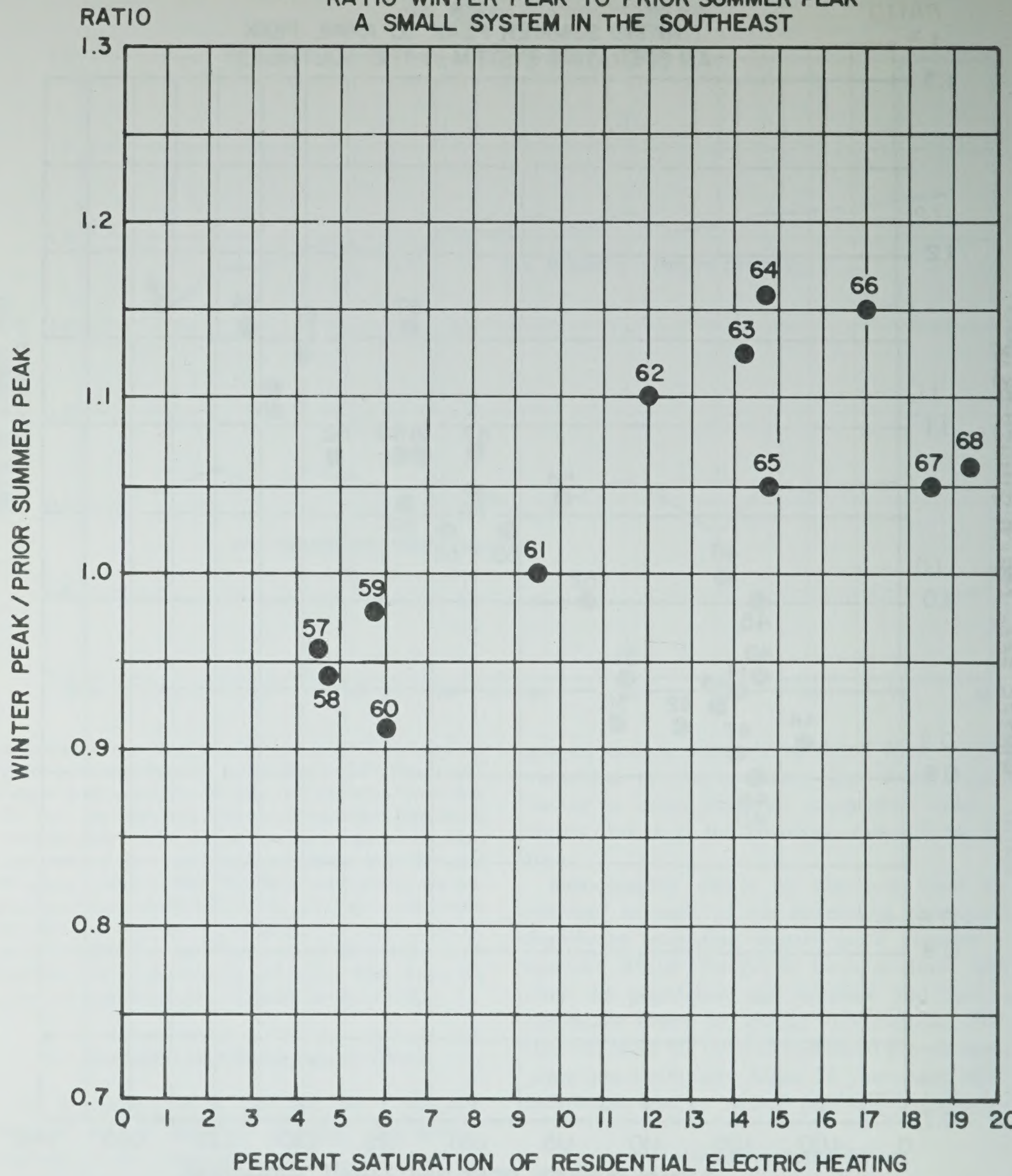
FIGURE 19
RATIO SUMMER PEAK TO WINTER PEAK
VS.
RATIO SUMMER PEAK TO APRIL PEAK
AN OPERATING SYSTEM IN THE SOUTHEAST



use some sort of annual sales quota which may take a variety of forms such as appliance units, annual energy requirements, connected load or estimated annual revenue. For the most part, these will not have a significant effect on the total load character of the system except in the case of major residential appliances and certain industrial devices.

In the longer term, promotional policies are aimed at changing people's buying and living habits. In such cases, even smaller electrical usage devices could have a significant impact on load patterns. Such promotional policies could be

FIGURE 20
RATIO WINTER PEAK TO PRIOR SUMMER PEAK
A SMALL SYSTEM IN THE SOUTHEAST



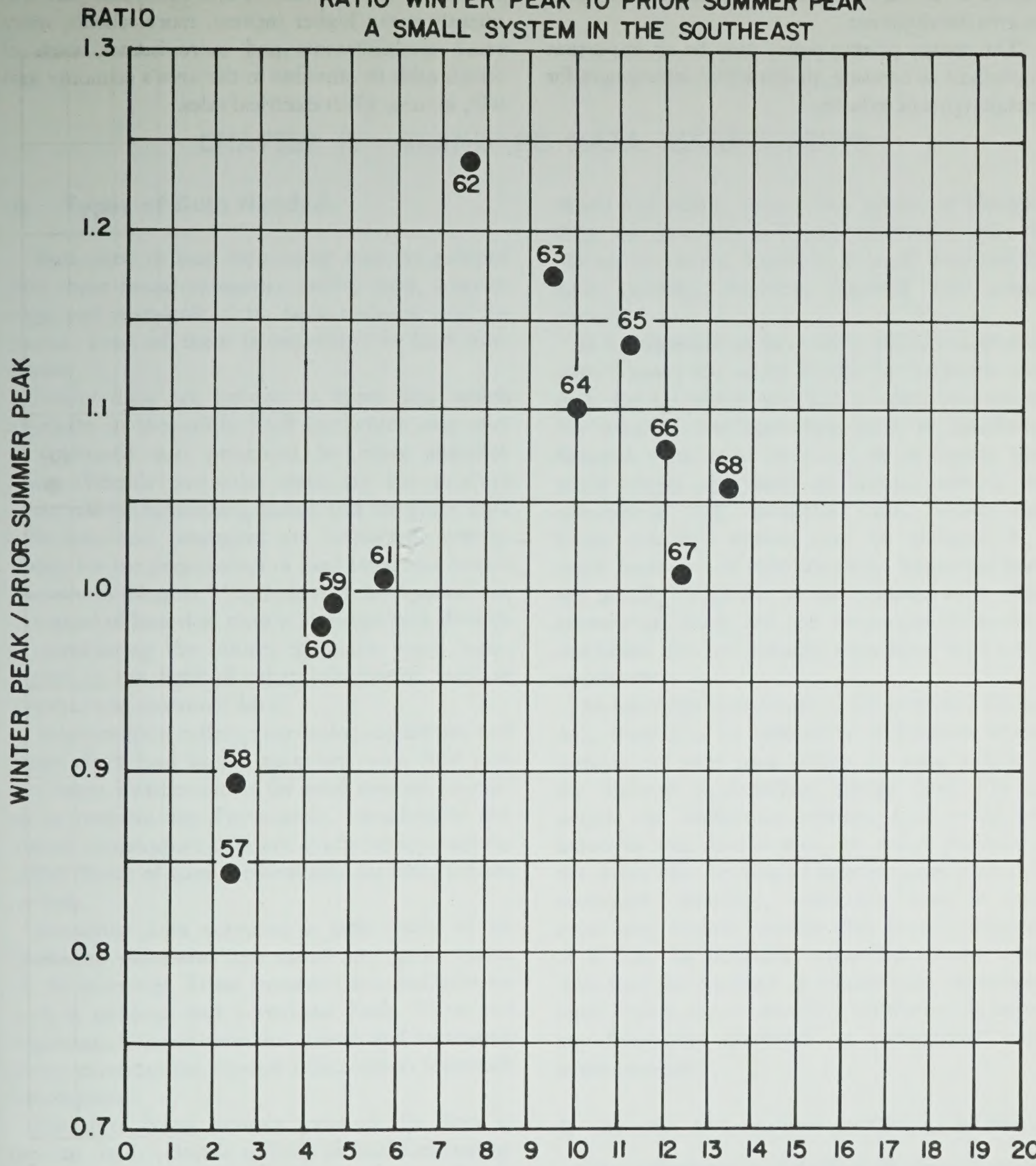
aimed at either of two objectives: gaining acceptance for an entirely new application or expanding the electric share of the market for existing applications.

b. Pricing

Pricing can be part of a promotional program but is also a separable variable affecting long-term load growth characteristics. Declining electric energy costs vis-a-vis competitive energy forms offer opportunities for increasing penetration of all markets.

This may take two different forms: (a) an increase in existing applications in residential, commercial and industrial markets and (b) increased acceptance of new electric energy consuming

FIGURE 21
RATIO WINTER PEAK TO PRIOR SUMMER PEAK
A SMALL SYSTEM IN THE SOUTHEAST



PERCENT SATURATION OF RESIDENTIAL ELECTRIC HEATING

devices which compete with other energy forms, such as the use of electric space heating in residences and commercial structures. The long-term importance of pricing is illustrated in Appendix B-1.

Under certain conditions, pricing may quickly produce changes in local characteristics. The inception, change or abandonment of off-peak rate provisions may have immediate consequences. Changes in interruptible rate provisions may have similar effects.

c. *Area Development*

Area development is defined as the coordination of planned efforts to develop communities and areas to their fullest economic potential. Included in these efforts are industrial development designed to create and maintain a high degree of economic

prosperity and community planning with the objective of encouraging communities to participate in area development.

The energy pricing policy may be an important ingredient in creating an attractive atmosphere for certain types of industry.

Improved industrial activity carries with it several ancillary effects. More industrial jobs frequently mean higher income, more schools, more retail establishments and more homes, each of which adds its stimulus to the area's economy and will, in turn, affect electrical sales.

CHAPTER IV—STANDARD DATA REQUIREMENTS

A. Types of Data Needed

Data used in load forecasting may be grouped into three broad categories: utility data, weather data and economic data, both national and regional. Each of these is important in load forecasting.

Utility data are defined as those data which originate in the utility itself but which also may be collected and presented by other agencies. Each system's particular data are the primary materials for forecasting. Load and customer data collection and treatment are important prerequisites for the preparation of load forecasts. As can be seen in Chapter V and most of the Appendices, the trend of historical data is an important element in considering the future, especially when interpreted in the light of other information such as weather and economic data.

Weather data reflect meteorological factors and these affect load in an important way. The predominant weather factor for most systems appears to be temperature. Fortunately, considerable historical temperature data are available for analysis. Other forms of data are available for only limited periods.

Economic data comprise a large body of information measuring the status and performance of the economy. These measures are available on both a national and a regional basis. These are important because customer growth and increasing power consumption depend ultimately on economic development.

The text below reviews some of the data in general use by electric utilities in load forecasting. For a more detailed list and major sources of such data see Appendix D. Some of the problems and inconsistencies of the data are discussed as are the methods of preparation and treatment of the data for forecasting.

B. Utility Data

1. Load Data

Load data (both demand and energy) are usually available or can be collected from log sheets and billing data. They consist of historical data on generation; hourly demands; sales by classes of service; losses; and peak demands for daily, weekly, monthly, seasonal and annual periods.

It is important to have clear definitions of these data because the series should be consistent over time and be related logically to other parameters. For example, confusion may arise in considering demand when some data are on an hourly basis while others are based on shorter periods. Or commercial and industrial loads, which may follow different trends, may be included in a single business and industry series. Industrial loads are usually responsive to the business cycle while commercial loads are less responsive to business conditions but are usually responsive to weather conditions.

As has been mentioned in Chapter III Section A.1, there can be substantial differences among systems and over time within the same system in the method of classifying energy data. For example, the distinction between commercial and industrial may not be used but rather the total ot the group may be divided between large and small customers. Similarly, residential load in rural areas may include considerable farm equipment, or it may be separately recorded, or the whole load may be reported as commercial. Apartment loads which appear basically residential in nature are frequently classified as commercial when master-metered.

2. Number of Customers by Classes of Service

The differences in definition of class of service discussed above generally apply here, too. Customer and sales data are frequently used to compute average use by classes of customers. Changes in such averages must be carefully interpreted in the light of classification practices and changes in such practices.

3. Special Metered Data

Loads may be metered to determine more accurately the components of total load. For example,

cooling and heating loads may be metered in sample areas as a means of learning their magnitude and characteristics. New loads appearing on the system, such as mobile homes, selected farm equipment or a specific type of industrial load may also be metered.

4. Marketing Data

Marketing data are helpful in appraising opportunities for future growth and the probable effect of competition. Major categories of such data are appliance saturations, public preferences and opinions and price of electricity relative to competing energy sources.

a. Appliance Saturations

Such data are commonly cast in terms of ownership or use of a specific appliance per customer or per household. They may be supplemented by reports of shipments of appliances by manufacturers. Care must be taken in the use of these statistics, since they may be based upon sample surveys and therefore incorporate shortcomings inherent in surveys such as bias, false response, non-randomness, etc.

Also, saturation is usually considered as having a ceiling of 100%. Several appliances—television, refrigerators, room air conditioners, for example—may be represented more than once in a growing number of households. Failure to account for multiple ownership leads to improper energy or market potential estimates.

b. Preference and Opinions

These are always based upon surveys and the same sample limitations noted under a. above apply. In addition, preference surveys must be handled with caution because subsequent actions may differ from expressed opinions.

c. Price of Electricity Relative to Competing Energy Sources

The relative price of electricity to a competing energy source, for example gas, may be useful in showing growth relationships which are dependent on price elasticity. However, it must be kept in mind that the relative price per million Btu received by the consumer does not necessarily reflect the cost of operating his devices. Efficiency of conversion of the two sources may be different. Comparisons over time may not be valid if there have been changes in relative conversion efficiency.

5. Special Considerations

Some considerations which may be important include examination of the effects on the load data of wheeling arrangements, interconnection commitments, special contracts with large industrial accounts and municipal and REA resale accounts. These data tend to be a discontinuous series and can affect the total system data in a significant way. These effects may be direct, such as the addition or cancellation of a large sales contract, or indirect, such as the influence on losses of a large wheeling agreement.

C. Weather Data

Weather data are varied and extensive. They include temperature, humidity, degree days, wind velocity and direction, precipitation and sky cover. Much data, especially temperature, are available in published form over several decades for most locations. Within the past decade the Weather Bureau (Environmental Science Services Administration) has developed other measures of personal comfort such as heating and cooling degree days, chill factor and temperature-humidity index. During the development stages many different ways were used to calculate these measures. Care must be taken not to mix these.

Special note should be taken that several different weather measures of heating or cooling needs may be pertinent to utility data. For example, in relation to cooling, energy may be needed to cool commercial buildings when the ambient temperature rises to 50 to 60 degrees. For residences, energy for cooling may not be needed until temperatures reach 75 to 85 degrees. Therefore, different bases of cooling degree days would be appropriate for each of these loads. Similarly, separate measures of heating degree days would be required in relation to heating effects.

Analysis of weather and its effect upon weather-sensitive loads should include probabilities of occurrence of weather phenomena in the future. Identification of probabilities of extreme temperatures are helpful because loads can be studied more precisely.[1] Future temperature may be predicted

[1] Annual peaks in one region, which has a high saturation of electric heating, have occurred at temperatures ranging from as high as 20 degrees to as low as −10 degrees. This is a 30-degree temperature swing in a region where winter loads currently vary about 100 MW per degree temperature change. If temperatures are 10 degrees colder than normal minimum temperatures, the load will be 1000 MW more than would be expected at normal minimum temperatures and, conversely, loads would be 1000 MW less if temperatures were 10 degrees warmer than normal.

with precision only in terms of probability. These, however, must be developed by each system to meet its requirements from basic Weather Bureau data.

D. Economic Data

A variety of economic factors influence loads. These include population and households, employment, income, industrial production, gross national product, construction and many others. These data can be helpful in explaining historical load behavior and thus suggest important considerations for forecasting in a given utility area. These data are available from a number of sources, some of which are listed in Appendix D.

It is important that the applicability of the data, as well as the concept and construction of the series, be well understood before being utilized. For example, in analyzing the volume of new customers, it is important that the conclusions take into account not only the standard single family and apartment units but also mobile homes. Or, data expressed in dollars must be examined for the effect of changing price levels, and it is often desirable to convert them to constant dollars to eliminate the effect of general price changes. Many of the series are periodically revised, sometimes in substance and coverage and sometimes only in terms of the precision of the measurement. Breaks in continuity are a factor for which the forecaster must be alert. In general, the use of these data as related to the consumption of electricity must be established through careful analysis of the past record by each forecaster.

There is a lack of reliable business indicators at the local political subdivision level, but several items of information such as census data, housing inventory statistics, labor market surveys, bank deposits and the like are frequently available and may be sufficient to prepare adequate analyses.

E. Adjustment of Data

Historical utility data may be adjusted to make them uniform in definition and coverage in order to increase their usefulness in forecasting. Significant changes in load resulting from strikes, plant shutdowns or other load interruptions can be added back to load to determine what the full potential load might have been. Such factors as leap year, changes in billing cycles and metering errors may require adjustments to eliminate distortion in the true growth of a data series. In general, historical data are more useful in forecasting when they are uniform by class and coverage and when any change of definition of the data is clearly recognized.

As pointed out in the preceding chapter, heating, cooling, and to some extent lighting and irrigation loads vary with weather factors. Calculation of the degree to which load varies with these factors is important because this allows adjustment of historical data to evaluate or eliminate the effects of weather extremes. Examples of such adjustments are given in Chapters V and VI, and Appendix A. Adjusted data can also be used advantageously in computing weather adjusted relationships for use in forecasting, such as load factors and coincidence factors.

F. Forecasts of Economic Data

A number of organizations publish forecasts of various segments of the national economy. Some utilities use such forecasts in preparing load forecasts. Perhaps the most widely used source in the electric utility industry is the McGraw-Hill, Inc., publication *Electrical World* in which forecasts of a group of related indicators are presented each September. These indicators are: FRB Index of Industrial Production, GNP, population, households, new dwelling units, consumer disposable income, total employment, manufacturing production workers and business capital investment. Forecasts are given by years for the next 5 years and at 5-year intervals for the next 15 years. A number of other sources of various forecasts and opinions on the future are given in Appendix D.

G. Assumptions

A forecast is no better than the assumptions upon which it is based. Preparation of assumptions frequently involves some analysis and adjustment of historic data. There is an interrelationship between the assumptions made for the load forecast and those made for economic forecasts. Electric utility loads are largely dependent upon factors which are outside the utility's control such as demographic and economic conditions. Therefore a forecast must include, implicitly or explicitly, assumptions about these factors. To the extent reasonable, it is usually helpful to examine factors affecting load and to make explicit assumptions about their future behavior.

Although some assumptions may be stated in general terms, they are more useful when stated specifically and in as much detail as reasonable. It is useful to arrange them in a form suitable for convenient review so that others may follow the reasoning and be able to ask questions and suggest changes. This facilitates review and periodic revision of the forecast. The making and recording of assumptions is properly an integral step in the forecasting procedure.

CHAPTER V—CURRENT FORECASTING METHODS

Forecasting techniques are tools. No single method or group of techniques in itself assures success in forecasting. Knowledge and judgment of the forecaster in applying selected techniques in a given utility load situation are essential. So is final judgment of the elements used in arriving at the ultimate load forecast.

The number and kinds of forecasting methods used vary considerably from utility to utility. Use of several methods is common. Differences in methods result in part from variations in economic and geographic conditions, system characteristics and mix of loads in the utility areas.[1] For example, population may change rapidly in one utility area and be stable in another. Utilities with large cooling loads have an interest in developing estimates of historical cooling loads and load weather relationships and use these in forecasting cooling loads. Utilities serving industrial loads which are highly responsive to the business cycle and which constitute a large proportion of total load usually put more emphasis upon analysis of industrial loads than do utilities serving a stable and small industrial load.

A. Basic Forecasting Methods

Forecasting methods can be grouped into two categories: extrapolation and correlation.

1. Extrapolation

Extrapolation is based upon the assumption that future growth will be a continuation of a discernible pattern of past growth. Specific methods include compound rates of growth, annual increments, fitting of mathematical growth curves and use of graphs of treated or untreated historical data.

Extrapolation often produces acceptable results because electric loads exhibit stable growth over rather long periods. Residential, outdoor lighting and service loads appear to be largely insulated from the business cycle. However, forecasters relying predominantly upon this method may fail to recognize underlying changes which eventually will affect future growth. For example, a succession of very hot summers might mask declining growth in non-air conditioning loads.

2. Correlation

Correlation relates electric power loads to selected associated factors. Correlation methods include scatter diagrams, simple correlation, multiple correlation and simple or complex models. While results from these techniques, especially the more sophisticated methods, cannot be accepted at face value but must be evaluated in terms of the theories underlying the techniques, including their limitations, they provide insight into the causes of past growth and its variation and quantify relationships between load and factors which affect load. This leads to a clearer understanding of the factors which cause growth and of their relative importance. Further, when forecasts deviate from actual loads, the correlation approach is helpful in identifying causes of deviation.

One problem associated with correlation methods is the need to obtain and select forecasts of these associated factors, i.e., independent variables, such as population, income, appliance saturation, etc. There is no assurance that this can be done with any greater accuracy than forecasting electric loads directly. Despite this difficulty, correlation is useful because it forces the forecaster to consider and analyze future load in a context of other factors rather than as a completely independent phenomenon.

It is important, however, that the analyst/forecaster avoid the mistake of drawing conclusions from spurious correlations which have a high degree of statistical significance but no logical relationship.

B. Special Information and Judgment

Although extrapolation and correlation are fundamental to the art of load forecasting, they

[1] Specific forecasting methods employed by four electric systems are detailed in Appendix A.

are not generally sufficient to assure the best results. Two additional ingredients that are often important to the development of a sound load forecast are the use of special information and the exercise of informed judgment.

1. Special Information

Special information is used to modify or reinforce the forecast. Examples include opinions of industrial plant managers as to probable future loads, planned utility promotion programs, the results of appliance surveys to determine present saturations and buying intentions, predictions of business activity and area and national electric power forecasts. Such information is not only an important indication of definite future planning for electric consumption by others, but also it is a stimulant to the forecaster in thinking about the possibility of new trends.

2. Informed Judgment

In forecasting, informed judgment is necessary in the selection of the factors to be analyzed and in the selection of the forecasting methods to be employed. It is also essential in determining the weight to be given to differing forecasts derived from use of several techniques. In uncertain situations when information is incomplete or when forces affecting load are not quantified, the informed judgment of the analyst is of particular importance. For example, he must decide whether forces favorable and unfavorable to growth of a new type of load are such that the new load is likely to become significant over the relevant planning period.

Finally, informed judgment plays a major if not decisive role in identifying likely future changes in trends, in selecting among competing forecasts of external forces such as economic activity and housing starts, in evaluating market penetration in such areas as air conditioning and heating and in identifying areas and degree of competition from alternate energy sources.

C. Survey of Industry Forecasting Methods

In order to determine the present state of the art of load forecasting in the industry, a survey was made of the current practices. Survey respondents were selected with the objective of including all types of systems, all areas of the country and all types of forecasting methodology rather than on a random basis. The survey-questionnaire was prepared and distributed through the FPC Regional Advisory Committees. Appendix E shows the format used. Thirty organizations responded. The techniques used by the respondents for short-term, intermediate-term and long-term load forecasting are discussed below.

The survey results reflect the dynamic nature of forecasting methodology in use during the period 1961–1967. Forecasting methods have evolved to meet the particular needs and individual characteristics of the various electric utility systems. Several respondents adopted changes in methods during the seven-year period; others mentioned changes that are being considered. This evolutionary process is found to be common in systems represented on the Committee as well as in the experience of those responding to the survey.

The wider daily and seasonal swings in loads experienced in the last few years and growth of new kinds of loads or changing patterns of growth of existing loads have been among the reasons for the search for new forecasting techniques. Another reason has been the increasing need for improved accuracy and more detailed forecasts to enable economic planning for greater use of energy interchange and larger generating units. Finally, improved forecasting methodology developed outside the industry along with the development and availability of greater computational capability also have been responsible for changes in load forecasting methodology.

1. Short-Term

Most utilities reported that hour-to-hour and day-to-day load forecasts are prepared by adding expected load changes to current or recent past loads. Nearly all reporting utilities indicated that expected weather conditions are considered in preparing forecasts 24 hours in advance. Half specifically report use of temperatures while only five refer to humidity or wind velocity. Nearly all indicated that historical hourly load patterns and day-of-week patterns are considered. Ten utilities report that changes in large industrial loads, strikes and other abnormal events are recognized in making the forecast.

Few of the reporting utilities use complex forecasting methods for short-term forecasting. However, a small number report developmental work to computerize hour-to-hour and day-to-day load forecasting, presumably to permit analysis of more

variables. One utility reports it is engaged in developing empirical formulae to automate short-term forecasting of hourly loads based on expected temperatures, previous temperatures and previous loads.

2. Intermediate-Term

In the survey questionnaire, intermediate-term forecasting is defined as covering a period of four to six years. The survey indicates that the most intensive use of statistical techniques is in intermediate-term forecasting.

a. Adjustment of Data

All utilities report adjusting historical data in some manner, i.e., making some form of preliminary analysis to eliminate the effects of cyclical, seasonal, or irregular factors prior to analysis of trend factor. More than half specifically report adjusting for the effect of weather, while others take weather into account through judgment or historical relationships. Five report adjusting for specific events such as plant shutdowns.

A quarter of the utilities specifically report use of formal statistical treatment. These include time series analysis, correlation analysis, analysis of variance and other such techniques. The remaining three-quarters report calculations based upon historical relationships; it is not clear from the survey responses whether these systems determine the historical relationships through formal statistical analysis.

b. Approaches

In the forecasting of loads, utility systems are using a variety of approaches. Four sets of approaches to various phases of load forecasting are set forth below.

(1) *Energy vs. Peak Demand*

About half of the reporting utilities prepare an energy forecast as the primary forecast, with a peak demand obtained by use of load factor relationships. The other half prepare peak demand forecasts directly. Several report less detailed forecasting of the secondary data to serve as a check on other methods. For example, one utility prepares energy forecasts in detail by classes of service and geographic areas and calculates peaks by use of load factor projections. As a check on these figures, weather-adjusted peaks are extrapolated on the basis of past trends.

Advantages claimed for emphasizing peak forecasts are that it is the most direct way to obtain what most systems consider the most important forecast; that load factors are frequently erratic and difficult to project; and that demand data can be related more directly to such variables as temperature.

Advantages claimed for emphasizing energy forecasts are that energy data are usually less erratic over time than peak data and are therefore a better indicator of underlying growth trends; that load factors are no more erratic than peaks in the short run and in many cases tend to be rather stable over long periods despite year-to-year variation; and that detailed data are available by classes of services, areas, or other sub-divisions and can be readily related to appropriate variables, such as weather, national economic indicators and population.

(2) *Total Load vs. Components*

About one-third of the reporting utilities prepare forecasts of system loads in total. The other two-thirds assemble peak forecasts either by geographic areas, by types of customers or by some other subdivision of load. Forecasts of the individual parts are combined and adjusted for losses and diversity to obtain a total system load forecast. Loss and diversity adjustments are based on historical relationships.

Proponents of the total load approach argue that it is difficult to perceive changes in trends in each load component, e.g., the sudden surge in residential air conditioning, the rebuilding of one area, a new industrial development. In addition, their experience has shown that the overall growth of demand and energy has been smooth in the past, rapid growth in one component offset by slower growth in another. Rather than trying to foresee each new application or change in use of existing applications for each component, they feel more confident in predicting the overall continuing rate of growth of their system.

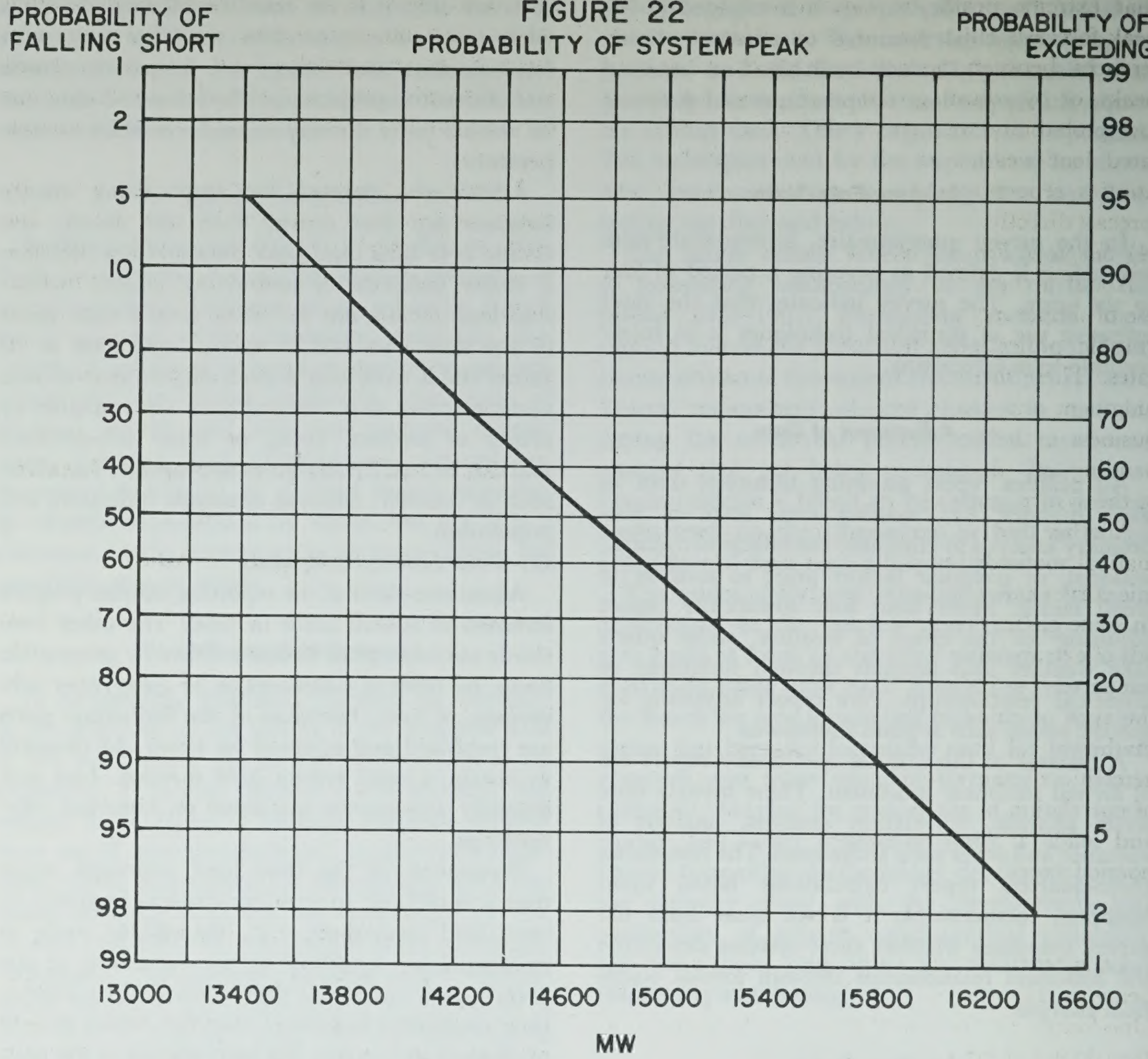
Proponents of the components approach argue that one part, e.g., a portion of the service area, a class of service, or a type of load, may be growing much more rapidly than the remainder. If this part is substantial and its rate of growth differs significantly from that of the total, failure to segregate it can result in misleading conclusions. Further, they argue that a great deal more detailed information can be more meaningfully correlated to the parts than the total.

(3) *Average Weather vs. Extremes*

Most utilities prepare forecasts designed to reflect normal weather conditions. Historical

FIGURE 22

PROBABILITY OF SYSTEM PEAK



THIS SHOWS THE FORECAST PROBABILITY RANGE, BASED ON WEATHER VARIABILITY ONLY, OF THE AREA PEAK FOR A SOUTH CENTRAL SYSTEM FOR JANUARY 1967. DATA WERE CALCULATED BY USING THE NORMAL WEATHER PEAK FORECAST AT 14 DEGREES, A GRAM-CHARLIER CURVE FIT TO 80 YEARS OF JANUARY HISTORICAL MINIMUM TEMPERATURES AND A FORECAST OF THE 1967 LOAD-WEATHER RELATIONSHIP PROJECTED FROM A SERIES OF HISTORICAL RELATIONSHIPS EXPRESSED IN MEGAWATTS PER DEGREE. FOR EXAMPLE, THERE WAS A 2 PERCENT PROBABILITY THAT THE JANUARY 1967 PEAK WOULD BE 16,400 MEGAWATTS OR HIGHER.

seasonal or monthly peaks are usually adjusted for weather using weather models or other computational methods to provide the basis for peak projections. Other utilities construct graphs of historical peaks, correlate them with temperatures at the time of peaks, fit a curve through the historical data and extrapolate. Both of these methods are designed to provide a normal peak forecast, or the peak which is most likely to occur if historical, average extreme conditions occur in the future. That is, it is equally likely that actual peaks will exceed or be less than the forecast.

Utilities experiencing greater variability in loads either from irregular weather or economic patterns are forced to consider loads under other than average conditions. This may take the form of stating forecasts in probabilistic terms or just a simple statement of the possible extremes associated with the forecast.

To obtain extreme forecasts, four utilities report

that extreme peaks are calculated from normal peak forecasts either on the basis of historical differences between normal and extreme weather peaks, or by adjusting of normal peak forecasts to low probability weather conditions using extrapolated load-weather relationships or models. Two utilities report that extreme weather peaks are forecast directly.

(4) *Simple vs. Formal Statistical Methods*

About a third of the reporting utilities indicate use of simple methods of forecasting which include graphic projections and use of historical growth rates. Their forecasts are usually tempered with judgment and influenced by considerations of the business cycle and other economic factors. Depending on the load and growth characteristics of the system, such methods often can be effective.

Another third of the utilities report use of mathematical methods involving least squares, logarithmic curves and modified exponential growth curves. In some cases, there are simply mechanical methods of extrapolation with the ultimate results being tempered by judgment. Other companies select the type of curve based on the relationship of its mathematical characteristic to the growth characteristic of the system. Four utilities report use of correlation or models through which customers and loads are related to demographic and economic factors.

3. Long-Term

Long-term forecasting is generally defined as being in the order of 10 to 30 years in the future. One-fourth of the utilities surveyed report that they do not prepare long-term forecasts.

Half of the remaining utilities report that long-term forecasts are extrapolations of intermediate-term forecasts based on judgment, compound rates of growth, fitted curves or some combination of these. The other half use a variety of methods.

One utility states that historical information, its intermediate-term forecasts and trend projections of economic indicators, such as GNP and the FRB Index of Industrial Production, are taken into account in its long-term forecasting.

Another utility reports that long-term forecasts are prepared by projecting energy requirements by rate classes using trends and marketing information. Historical relationships are used to obtain demand contributions of the various rate classes to the system peak demand. Typical demands for each class of customers are derived from sample demand metering of a statistically selected group of customers.

A utility with large in-migration of population reports that long-term forecasts are based on land use and land-use trends. Land uses are analyzed and divided into 12 categories. Relationships between land-use categories and related demands are established by load surveys.

A detailed method of long-term forecasting by classes of service is reported by one utility. The method includes trend projections and correlations, such as residential customers per commercial customer, correlation of annual changes in industrial sales with changes in GNP and correlation of agricultural sales with rainfall conditions.

D. Statistical Analysis of Survey Results

1. Description of Data

Tables 23 and 24 summarize the data reported in the survey and analyzed below. These data represent two different kinds of measures. The first is either a trait of the forecasting method or a characteristic of the system which might influence accuracy of forecasting. The second is a measure of relative success in forecasting and is used here as the dependent variable of the analysis.

a. Dependent Variables

Data from the survey-questionnaire provide percentage deviation of forecasts from actual data for each year 1961 through 1967. To reduce the volume of data in the analysis, the Committee used forecasting deviations on only three bases: (1) The average absolute forecast deviation for the years 1965, 1966, and 1967 of the forecasts made 5, 4, and 3 years in advance; (2) The average absolute forecast deviation for the years 1965, 1966, and 1967 made 2 years and 1 year in advance; and (3) The average absolute forecast deviation for the years 1965, 1966, and 1967 made 1 year in advance. Separate measures are shown for the peak demand forecasts and the energy forecasts. Individual values for each system and the mean value for all reporting systems are shown in Table 24.

Several alternative measures have been calculated to test whether these three sets of values are representative. While different calculations of deviations result in slightly different values, no statistically significant differences have been found.

TABLE 23

Summary of Load Forecasting Survey Returns, System Characteristics and Forecasting Methods

Company	Size of system 1: 0–1500 Mw 2: 1500–5000 Mw 3: Over 5000 Mw	Percent Residential sales	Percent Industrial sales	1967 Ratio of summer to winter peak demand	Peak demand (1) vs. energy (2) both (3)	Total (0) vs. component (1)	Simple ( ) vs. complex (1) analysis
1	1	NA	NA	0.63	2	1	0
2	3	24	41	.76	2	1	1
3	1	37	36	1.25	1	0	1
4	2	24	44	1.20	2	1	0
5	2	36	43	1.01	1	1	0
6	3	25	34	.98	2	1	1
7	1	33	30	.83	1	0	0
8	2	48	25	.64	2	1	0
9	2	22	48	.93	2	0	1
10	2	25	37	.90	1	1	0
11	1	22	41	.96	1	0	0
12	2	NA	NA	.83			
13	NA	25	43	1.15	2	1	0
14	3	29	25	1.00	2	1	1
15	2	33	41	.84	2	1	0
16	2	28	20	1.01	3	0	1
17	3	24	37	1.11	1	1	1
18	1	27	28	.89		1	1
19	2	47	13	.94	1	1	0
20	2	25	35	1.54	1	0	0
21	1	NA	NA	.70	1	0	1
22	NA	NA	NA	NA	2	1	0
23	2	26	37	1.04	2	1	0
24	2	32	33	.84		1	1
25	NA	24	NA	1.16	2	1	0
26	2	24	52	1.05	1	1	1
27	2	24	51	.91	2	1	1
28	2	21	49	.91	2	1	0
29	2	15	57	1.27	1	1	1
30	1	4	NA	1.28	3	0	0

(NA) Denotes not available.

As would be expected, forecasts prepared 1 or 2 years in advance are more accurate than those prepared 5, 4, and 3 years in advance. The table below compares average differences for all companies.

Time of forecast	Average difference mean of reporting companies (percent) Demand	Energy
5, 4, and 3 years in advance	5.2	4.8
2 and 1 year in advance	3.8	3.2
1 year in advance	3.5	2.7

While the above reflects averages, inspection of individual system responses in Table 24 shows some notable exceptions. These probably result from unusual conditions for the year forecast. Since very few systems provide adjusted data, it is impossible to determine with certainty whether this is true.

Inspection of the data also reveals very large variations in differences among systems, running from a high of 15.1% to a low of 0.6% on peak and 12.1% to 0.5% on energy. Large variations are frequently caused by unusual problems for the system. For example, in one case, rapid growth in industrial load stopped abruptly for causes completely beyond the system's ability to foresee. In another case, forecast increases in air conditioning installations occurred, but the summers were cooler than normal in the years examined by the survey.

Table 24 shows that on the average the differ-

TABLE 24

Summary of Load Forecasting Survey Returns, Average Difference Between Actual and Forecast

Company	Forecasts prepared (1) 5, 4, and 3 years in advance		Forecasts prepared (2) 2 and 1 year in advance		Forecasts prepared (3) 1 year in advance	
	Demand average difference (percent)	Energy average difference (percent)	Demand average difference (percent)	Energy average difference (percent)	Demand average difference (percent)	Energy average difference (percent)
1	5.6	NA	6.7	NA	6.9	NA
2	3.2	4.3	2.2	1.1	1.9	0.9
3	5.5	NA	5.1	NA	5.5	NA
4	1.8	7.7	1.6	6.3	1.5	5.6
5	2.2	2.7	5.1	1.7	5.4	1.2
6	4.5	6.9	3.1	2.2	1.5	.5
7	13.7	4.6	5.9	1.0	5.6	1.1
8	3.7	1.7	3.3	1.1	2.4	1.3
9	5.1	10.5	3.5	4.2	3.5	2.5
10	3.1	4.7	2.3	3.2	2.4	2.6
11	NA	NA	NA	NA	NA	NA
12	15.1	7.5	10.4	11.0	9.8	12.1
13	2.4	1.6	2.6	1.2	3.3	1.4
14	2.7	2.5	1.8	1.2	2.0	1.0
15	10.7	9.7	4.7	4.1	3.1	2.7
16	3.2	2.0	2.5	2.3	1.7	2.5
17	2.7	4.0	3.4	3.1	3.7	2.7
18	6.8	8.2	4.1	4.3	3.7	3.1
19	7.7	1.4	6.0	1.4	6.0	1.4
20	3.5	NA	3.5	NA	3.5	NA
21	2.8	NA	1.2	NA	.6	NA
22	NA	NA	NA	NA	NA	NA
23	1.8	4.1	2.0	4.1	1.6	2.6
24	5.7	4.2	3.8	4.7	2.7	2.7
25	3.8	.6	4.7	.6	4.8	.7
26	4.4	7.5	3.0	4.8	2.9	4.0
27	1.9	6.7	2.0	4.8	2.0	3.1
28	10.8	5.8	4.0	4.7	3.4	4.6
29	3.0	2.0	1.6	2.0	1.5	2.0
30	7.4	3.7	6.0	3.6	4.7	3.4
Average	5.2	4.8	3.8	3.3	3.5	2.7

* Percent average difference for the years 1965, 1966 and 1967.

ences between forecast and actual results are smaller for energy forecasts than for demand. Individual system results, however, vary significantly from this generalization. As mentioned in earlier chapters, energy series tend to be more regular in that they are the integral of the instantaneous conditions over a period of time—in this case one year. Demands reflect conditions over a short span of time, in this case a one-hour period.

b. Independent Variables

Three of the independent variables represent differences in forecasting techniques reported in the survey. These are peak demand versus energy forecast, total versus components forecast and simple versus statistical methods.

Other extraneous causes for variations, such as extremes in weather or variations due to business cycles, cannot be isolated as well due to lack of sufficient data. However, by grouping systems by characteristics, the effects of such variables might be discernible. The following variables are used to pool like systems: relative size of system, residential sales as a proportion of total sales, industrial sales as a proportion of total sales and summer versus winter peaking.

TABLE 25

Results of T–Test Load Forecasting Survey

Comparison: Item A and Item B	Forecast	Mean A	Mean B	T	°F	Significant to 0.05 level
Forecasting methods						
Prediction: Energy vs. Peak demand	KW	4.71	4.86	−0.1	18	
Prediction: Peak demand vs. Both	KW	4.86	4.30	.3	13	
Prediction: Both vs. Energy	KW	4.30	4.71	− .2	13	
Prediction: Energy vs. Peak demand	KWH	5.40	3.84	1.1	14	
Prediction: Peak demand vs. Both	KWH	3.84	3.84	.0	10	
Prediction: Both vs. Energy	KWH	3.84	5.40	− .9	12	
Prediction: Component vs. Total	KW	4.42	5.89	−1.1	25	
Prediction: Component vs. Total	KWH	4.54	5.20	− .4	21	
Complex vs. Simple analysis	KW	3.96	5.59	−1.4	25	
Complex vs. Simple analysis	KWH	5.35	4.02	1.1	21	
System characteristics						
Residential sales 0–30% vs. Residential sales 30–100%	KW	4.01	6.85	−2.4	24	[1]Yes
Residential sales 0–30% vs. Residential sales 30–100%	KWH	4.87	4.05	.6	21	
Industrial sales 0–30% vs. 30–40%	KW	6.35	3.83	1.7	13	
Industrial sales 30–40% vs. 40–100%	KW	3.83	4.55	− .5	15	
Industrial sales 40–100% vs. 0–30%	KW	4.55	6.35	−1.1	16	
Industrial sales 0–30% vs. 30–40%	KWH	3.44	4.78	−1.1	10	
Industrial sales 30–40% vs. 40–100%	KWH	4.78	5.85	− .7	13	
Industrial sales 40–100% vs. 0–30%	KWH	5.85	3.44	1.7	15	
0–1500 MW vs. 1500–5000 MW	KW	7.02	5.81	.5	13	
1500–5000 MW vs. Over 5000 MW	KW	5.81	3.55	.9	12	
Over 5000 MW vs. 0–1500 MW	KW	3.55	7.02	−1.7	7	
0–1500 MW vs. 1500–5000 MW	KWH	6.40	5.00	.6	10	
1500–5000 MW vs. Over 5000 MW	KWH	5.00	3.95	.6	12	
Over 5000 MW vs. 0–1500 MW	KWH	3.95	6.40	−1.1	4	
Summer peak demand vs. Winter peak demand	KW	3.42	6.69	−2.7	26	[1]Yes
Summer peak demand vs. Winter peak demand	KWH	3.49	5.86	−2.3	22	[1]Yes

[1] Not significant at the 0.01 level.

2. Description of Analysis

Statistical tests have been employed to determine whether the variations in forecasting results are traceable either to the methods employed in forecasting or to the intrinsic character of the system doing the forecasting. A simplified analysis of variance does not show any significant relationships among the variables because there was not enough variety among respondents.

Also, a simple statistical comparison, T-test, is applied. The results are shown in Table 25 and indicate some reasons for variation in forecasting. These are discussed in greater detail below. It should be remembered that a T-test may not reveal significant differences if there is significant covariance or an absence of randomness.

3. Results of Analysis

Table 25 shows the results of the series of statistical comparisons between various pairs of data. The first two columns indicate the groups being compared. The third column shows whether the demand (KW) or energy (KWH) forecasting deviation was analyzed. The columns headed "Mean A" and "Mean B" show the mean deviation of each forecasting group. The column headed "T" is the statistical result, namely Mean A less Mean B divided by the standard error of the sample-mean differences. The heading "°F" means degrees of freedom. The final column indicates whether differences between Mean A and Mean B are statistically significant.

Other than two cases described below, no comparison has statistically significant differences. While there are some large differences among the means, the variation of the data making up a given mean is also very large. As indicated by the T-test, pure chance is as likely a cause of differences between means as variation in characteristic.

This is especially true among the variables

representing variations in forecasting technique. These results are shown in the first ten lines of the table. One may infer that the significant variations are hidden within other factors not isolated in the analysis or that different techniques are appropriate for different system situations.

The T-test indicates that winter peaking systems have significantly greater forecasting deviations than summer peaking systems in both demand and energy. This appears reasonable since variability of winter temperature is generally greater than for summer temperature and since 4 of the 16 winter peaking systems in the survey clearly have large electric heating loads.[2] However, summer peaking systems with substantially larger summer weather sensitive loads than winter weather sensitive loads generally experience greater forecast deviations in the summer.

TABLE 26

Differences by Size of System

Years in advance	Size of system in MW		
	0–1500	1500–5000	Over–5000
5–4–3:			
Demand	7.0%	5.2%	3.3%
Energy	5.5	5.2	4.4
2–1:			
Demand	4.8	3.7	2.6
Energy	3.0	4.0	1.9
1:			
Demand	4.5	3.3	2.3
Energy	2.5	3.4	1.3

The test also indicates that systems with a higher proportion of residential sales have significantly greater deviation in demand forecasts than systems with a low proportion of residential sales. The reason for this may be that most of the former also have winter peaks.[3] It is interesting to note that

[2] For example, one such system has winter peaks because 3 out of 10 homes are electrically heated. Both heating and cooling loads vary about 100 MW per degree temperature change on this system. However, there is a one in ten probability that summer maximum temperatures will be 5 degrees hotter than normal. By contrast there is a one in ten probability that minimum winter temperatures will be 14 degrees colder than normal.

[3] Of the above seven systems with residential sales 30–100%, four also had pronounced winter peaks in 1967. These four systems had large electric heating loads. Thus, most systems in the survey with a large percentage of residential sales had large electric heating loads, which, together with the greater variability of winter weather, may explain why they had greater deviations in demand forecasts.

TABLE 27

Differences by Demand versus Energy

Years in advance	Forecast emphasis	
	Demand	Energy
5–4–3:		
Demand	4.9%	4.5%
Energy	3.8	5.2
2–1:		
Demand	3.7	3.3
Energy	2.5	3.0
1:		
Demand	3.7	2.9
Energy	2.1	2.2

TABLE 28

Differences by Total versus Components

Years in advance	Forecast method	
	Total	Components
5–4–3:		
Demand	5.9%	4.4%
Energy	5.2	4.5
2–1:		
Demand	4.0	3.4
Energy	2.8	3.0
1:		
Demand	3.6	3.1
Energy	2.4	2.3

TABLE 29

Differences by Simple versus Complex Analysis

Years in advance	Type of analysis	
	Simple	Complex
5–4–3:		
Demand	5.6%	4.0%
Energy	4.0	5.4
2–1:		
Demand	4.2	2.9
Energy	2.8	3.2
1:		
Demand	3.9	2.6
Energy	2.4	2.3

Note: Data are indicative only; and as shown in Table 25 the differences are not statistically significant. Further, since the groupings in these tables are slightlv different from those in Tables 24 and 25, it is not possible to compare means directly.

the difference is not significant in the energy forecasts. In general, this is consistent with the observation that energy forecast deviations are generally less than peak demand forecast deviations.

Tables 26 through 29 summarize data collected in the Committee's survey. Table 26 shows the average differences between the forecast and actual loads for various time periods grouped by size of systems. Tables 27, 28, and 29 show similar information with systems grouped in accordance with the forecasting methods employed: Table 27, whether demand or energy is the basic forecasting series; Table 28, whether total load or components of load are utilized; and Table 29, whether the type of statistical analysis used is simple or complex. It must be emphasized that the average differences between forecast and actual loads set forth in these tables are not statistically significant at the 5% level. Consequently, the material contained in these tables must be handled with considerable care in reaching any conclusions based upon them.

CHAPTER VI—THE PROMISE OF NEW METHODOLOGY

New forecasting methods are continually developing. Earlier chapters have concentrated on changes in forecasting technology arising from forces within the industry. This chapter reviews the possible impact on load forecasting of stimuli outside the industry, primarily new methods used in other industries and advances in computational capability.

Advances in forecasting outside the industry have not as yet been reflected completely in techniques used by electric systems. For example, economic modeling techniques are becoming important tools and can be applied to load forecasting. Models not directly related to the economy also have applicability. Some limited use of these has been made in the industry, but there are many areas which offer promise provided the necessary development work progresses.

The widespread use of computers has increased the capabilities for data accumulation, analysis and presentation. Further impact is foreseen. Improvements in data availability will change forecasting approaches and make possible a wider variety of estimates, all aimed at reducing the uncertainties about future loads. New and improved data both from within the industry and from the economy as a whole should become economically available in the future.

A. Application of Modeling Techniques

1. Economy-Based Techniques

Economy-based techniques offer possibilities for new forecasting methods for the utility industry. They demonstrate logical relationships between economic factors in the business environment and electric utility load.

These relations can be illustrated by proceeding from detailed national output forecasts, through allocation of national industrial output to regions, to the use of energy by various industries and to projection of residential and commercial energy use from the population and income implied by the region's projected growth.

The approaches described below are still largely experimental for utility forecasting but are being successfully applied in other industries. However, much basic work has been done and trial applications are now within the reach of many systems. Much testing and study are needed to adapt these approaches to practical utility forecasting.

a. Input-Output Models

A national model to be used for regional forecasting should contain considerable detail by industry because the composition of industrial growth strongly affects the regional location of added production so important to a utility system. One source of such detail is inter-industry—or input-output—forecasts.

An input-output model is an industry-by-industry mathematical description of the requirements (inputs) to produce goods or services (outputs). Such models have been developed for the nation and for specific regions. The model can be made to operate so as to simulate the passage of time and hence produce forecasts.

These forecasts have built-in consistency with the technological relationships between industries. For example, the forecast for steel depends upon the demand for automobiles, machinery and construction; the demand for electricity depends upon the output of aluminum, steel, chlorine, printing, automobiles and so on. Projections of technological change may be incorporated in the model. Appendix B-3 describes input-output models.

(1) *National Forecasts*

National input-output projections are as yet rare. One was recently made by an interdepartmental committee of the federal government. As first published, it looked ahead to the year 1970[1], but it is currently being extended to the year 1980. It describes the methodology and contains a useful bibliography. Another is regularly prepared by

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[1] *Projections 1970, Interindustry Relationships, Potential Demand and Employment,* U.S. Dept. of Labor, Bureau of Labor Statistics, U.S. Government Printing Office, Washington, D.C., Bulletin No. 1536.

Bureau of Business and Economic Research of the University of Maryland[2] for a decade ahead.

(2) *Regional Forecasts*

To predict the extent to which a utility's area will participate in the nation's economic fortunes, one should study not only how well that area has done but also how similar areas have fared. This enables one utility to apply the experience of others. Multiple regression with counties as the geographic unit of observation offers a systematic way to make such an analysis. An extensive study of this sort has been sponsored by the Economic Development Administration[3]. This study divides the growth of an industry in a region into two parts, the regional *share*—how much the industry would have grown in the region if it had grown at the national rate—and the regional shift (or competitive effect)—the difference between the industry's actual growth and the regional share[4]. The regional shifts are most important. A number of variables are used to explain them: regional shifts in industries, shifts in population and income, the extent of specialization in an industry, wage rates and per capita income. Account is also taken of a large number of other distinguishing characteristics, such as whether the area is highly urban, is a major petroleum producer, is on the seacoast, etc. A few typical equations are shown and discussed in Appendix B-3.

These forecasts suffer from several shortcomings. The more important are the inadequacies inherent in the employment and other data on which they are based, the long lag between censuses and the problems of deriving production estimates from employment data. The use of current state and county employment statistics can overcome many of the shortcomings noted above. Even though such model forecasts cannot specifically identify the size and location of individual large new plants, they do reflect regional growth of each industry. They are superior to simple trend extrapolation, for they take into account the inter-relations of growth among industries.

The final step is to translate the regional production into industrial use of electricity. This translation has not yet been made, but the methods used at the national level could be applied to regional level analysis[5].

b. Other Economy-Based Applications

Two additional methods are particularly noteworthy: econometric models and use-by-use analysis. They may be used independently or in conjunction with the regional and national forecasting described above.

The econometric equation approach may be used for various components of demand or energy. For example, in forecasting residential use, a mathematical relationship is developed between total residential use and a number of relevant "independent" variables such as population, income per capita, size of households and the ratio of electric prices to gas prices. Such equations have been fitted for national data, and found to provide quite accurate forecasts.[6] Two examples are given in Appendix B-1. Some of the independent variables needed for forecasting with the equations can be derived from the regional forecasting models described in this chapter.

The use-by-use approach described in Appendices A-1 and B-2 and illustrated in Table 8 employs saturation estimates of a number of individually identified applications, such as space heating, air conditioning, lighting, water heating, cooking, and so on. Next, annual use per appliance or application is projected. Combining these two elements with the estimated number of future customers yields a projection of total residential load. A degree of consistency with the input-output model can be maintained by using the same population estimates.

c. Problems with Economy-Based Models

Of the two methods, the econometric method requires less data to apply and may give reasonably

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[2] This model is described in *The American Economy, to the Year 1975* by Clopper Almon, Jr., Harper & Row, New York, 1968.

[3] Harris, Curtis, Jr. *State and County Projections: A Progress Report of the Regional Forecasting Project*, Bureau of Business and Economic Research, University of Maryland, 1969.

[4] One of the best discussions of the "shift-share" method (which goes back to the forties) is contained in *Regional Change in a National Setting*, by Lowell D. Ashby, Staff Working Paper in Economics and Statistics No. 7, Regional Economics Division, Office of Business Economics, U.S. Department of Commerce, April 1964. Mr. Ashby is now with the Economic Development Administration of the Department of Commerce. The method has been used extensively in *Region, Resources and Economic Growth*, by Perloff, Dunn, Lampard and Muth, Johns Hopkins Press, Baltimore, 1960. Both explanation and application may be studied there. But no projections were made.

[5] See Appendix B–2 for one example of this technique made on the national level by Resources for the Future.

[6] Since these forecasts are for the nation as a whole, and for annual energy totals, the effects of weather variables are minimized.

accurate results for five or six years ahead. For the more distant future, the use-by-use method has the advantage that it explicitly takes into account both technological changes, as in house heating, and saturation effects, as in air conditioning.

While these economy-based models provide a basis for linking energy forecasts with related economic factors, they depend crucially on the forecast of such economic factors. In addition, there are inadequacies in some of the basic data. This is especially true of regional data made to fit the requirements of a specific utility system. It should be noted that data for larger aggregates may contain errors large in magnitude and limited to one sector of the economy, but small in proportion to the total. For a given utility system such data may be extremely difficult to work with if that specific sector represents a substantial part of the area's economic base.

Because such techniques are heavily dependent on historical relationships they are difficult to adjust for industries or applications unknown today but expected in the future as the result of continuing technological development. However, they share this shortcoming with most—if not all—methods.

The economy-based techniques have, until now, been used for energy rather than peak forecasting. By establishing the peaking characteristics of the various components of load, it is possible that these techniques could be extended to demand forecasting. The practice of using the energy forecast as base is employed already by a number of systems (see Chapter V).

2. Non-Economy-Based Models

Several forecasting methods discussed in Appendix A, specifically A–3, A–4 and A–5, depend upon models which are not mainly concerned with economic relationships. The growing importance of weather effects, in two cases, and demographic characteristics, in the other, require the modeling of these variables.

Uncertainty about future weather conditions and the large effect of weather conditions on load, have led to emphasis of the probabilistic nature of forecasts. While the weather models deal primarily with summer conditions, such techniques can handle both summer and winter conditions. Similarly, while those models are applied specifically to demand, they could also deal with energy data.

TABLE 30

Peak Day Definitions

[These are examples of the specific definition of a typical peak day used by a system in the East Central Region]

Winter:	
Period	January 3 to 31
Day	Monday
Time	a.m. between 10 and 12
Temperature	−2° to 3°—minimum of day
Wind velocity	15 to 18 m.p.h. at peak
Light intensity	500 to 1000 foot candles at peak
Summer:	
Period	July 15 to August 31
Day	Monday
Time	p.m., between 1 and 3
Temperature	93° to 95°—maximum of day 71° to 73°—a.m. minimum
Relative humidity	89 to 92% at 7 a.m. 58 to 61% at 1 p.m.
Continuity	Similar temperatures and relative humidities on previous day

The development of weather models consists of identifying weather sensitive load by correlating demand data with weather information, leaving a residual underlying growth trend. Appendix A–4 describes one technique in detail. To the extent that the model of historical relationships can be assumed to be valid for certain periods, forecasts of average weather conditions, along with probable deviations from average, can be used as inputs. From this, forecasts of demand can be derived as dependent variables.

Each user of these models plans further work. New variables may be found by expressing data in new ways or including data previously not available. Increasing the number of weather data stations to further localize the weather data is one possibility.

The demographic model described in Appendix A–3 is a technique which might well be applied by systems serving areas with wide fluctuations in population migration. It is possible that other systems might find such a tool useful if there were radical swings in housing construction or changes in emphasis between apartment and single family dwelling construction. Similarly, systems with large economically stagnant neighborhoods which are being redeveloped or experiencing a resurgence of growth might find a demographic model of value.

As contrasted with natural changes in service area population, i.e., the net effects of births and

deaths, population changes due to net migration have a nearly instantaneous impact on load growth.

The annual migration of families and individuals among some utility service areas is a significant phenomenon. The families and individuals participating in population flows may reflect increased mobility of members of the American labor force seeking to improve their economic status, military personnel moving in response to changing defense policies and operating programs or affluent college students seeking independence from their families as well as an education. In addition, the climatic and economic characteristics of some areas of the nation are particularly attractive to persons who have reached retirement age and encourage their relocation.

The techniques for developing a demographic model consist of correlating changes in population with changes in numbers of residential customers. Average kilowatthour consumption estimates per residential customer then permit a measure of the expected consumption impact on the entire residential sales class. Further correlations between the number of residential customers and the number of commercial customers give an indication of the effects of changes in the size of the consuming population on commercial energy sales. For many systems the sum of the residential and commercial classes account for at least 50% of the annual KWH sales.

The most serious constraint in using the demographic approach is the dearth of timely population data for individual utility service areas. Accurate population counts are available from the decennial census; for intermediate years it is necessary to estimate population indirectly through the use of such indicators as active electric utility residential accounts, average daily attendance of children in schools and registrations of private motor vehicles. Statistical estimates of population can be checked by special census studies and demographic questions included in appliance saturation surveys.

A model describing growth as a function of interfuel-price relations might be useful in understanding and forecasting loads in an area in which the interfuel competition is especially acute. It might be, for example, that the price ratio between fuels could provide clues to the electric heating potential (i.e. elasticity curve) to help determine the probable growth in winter loads.

Since models are merely mathematical representations of the system, the problem is to find all the important variables and quantify them such that they may be included in the model. Whether the cost of modeling is worthwhile depends on the forecast accuracy achieved and on the improved understanding of the responses of the electric system to changes in the variables which the models demonstrate. Modeling still depends on the underlying assumptions in the forecast of the variables. It may be extremely difficult to forecast, with any accuracy, certain of the model variables. A probabilistic approach brings this problem out into the open by showing the uncertainty in the forecast.

B. Developing Computer Applications

There are three principal areas in which large scale computer facilities have affected increasingly electric utility forecasting methodology: data accumulation, data adjustment or analysis and probability forecasting. This does not mean that these areas of forecasting were ignored in the past. Rather, computer capability makes more work in these areas feasible.

1. Data Accumulation

A great deal of detailed data, especially on energy use, are available to the forecaster. The problems lie in the cost of selecting and accumulating applicable data and reducing them to manageable proportions.

Computers have been little used to accumulate data directly. Within the next decade, however, direct electronic recording of data in computers used for system load dispatch will materially increase system energy and demand data availability. New equipment such as magnetic demand recording meters and their associated computer translation will make available much hourly energy and demand data on individual large customers. Currently, much work is being done in data reduction (i.e. translation) for forecasting purposes. For example, a number of utilities use detailed Weather Bureau tapes and integrate this information with their data system. Further development in this area appears reasonable as the speed and cost of computer processing improve. Some utilities already summarize customer billing information for energy forecasting by area or class of customer. It may be helpful to add appliance information to the customer billing file for forecasting as well as marketing purposes. Economic or demographic data might be added also for developing relationships between load and these data.

2. Data Analysis

Several of the sections in Appendix A discuss correlation analysis of historical data. The number of variables often make hand calculations impractical. Use and testing of correlation analyses have increased during the past decade. It appears reasonable that as larger core storage computers become available and data become less expensive to accumulate and reduce, even larger and more detailed correlations will be examined.

Appendix B contains descriptions of econometric approaches. Input-output modeling is dependent on computer processing capability. While it is possible to conceive of the theoretical framework of an input-output model without a computer and to develop it with a large expenditure of manpower and time (as was done in the late thirties and early forties), solutions, especially of complex models, can best be found with the aid of computer programs.

Other economic and statistical modeling techniques beginning to be applied—such as demographic modeling, modeling of technological change or modeling of market impacts of competition—all depend on large data processing capability. It seems likely that new theories and more detailed application of old theories will be tested in the next few years.

3. Probabilistic Forecasting

Forecasts are often stated as a single figure. However, more utilities are building probability into forecasts. Probability relates to two distinct kinds of uncertainty. The first relates to the conditions being forecast—i.e., economic levels, weather conditions, time of day and year, etc. The second relates to the uncertainty associated with the relationships being projected into the future—i.e., growth in use per customer, growth rates in saturation of electric heating or air conditioning, etc. With computer capability, calculation of probabilistic levels of the first and a number of tests of differing assumptions on the second are feasible. These can be combined in a statement of degree of certainty about a given forecast.

For systems in which weather effects are an important consideration, determination of a probable distribution of such effects is an interesting problem. The first step is to define the important variables; e.g., temperature on the day of the peak, on the previous day, etc. (See Appendix A-4 for one system's list of such variables.) The second step is to calculate the joint probabilities of occurrence of these variables; e.g., not only the probability of the peak day having a temperature of 95°, but at the same time having had a temperature of 90° on the previous day, etc. Such a distribution can then be used to calculate the probability of reaching various levels of demand in the future.

Such probabilistic forecasts can be developed into an integral part of the reserve margin calculation provided other input data are also stated in such terms. Such use of probabilistic forecasts in capacity planning may make calculation of interchange potential between systems somewhat more precise and help to simplify some of the more difficult calculations of interchange capability.

C. Contribution of Improved Data

1. Collection Techniques

An electric system's file contains much information of value for forecasting. From the billing records it is now possible to assemble customer counts and usage data by ranges of energy use, by areas and by certain limited appliance groups (usually water heating or space heating).

A further possibility might be adoption of census codes for each residential account to identify the type of residence—free-standing single family unit, row home, apartment, mobile or cottage. With this control, data could be assembled to determine not only the growth of types of units (by sub-areas within the system if necessary) but also the energy use characteristics and their contribution to the total. Although more demanding, major appliance equipment codes might also be adopted for similar analyses.

Similar gathering and handling of information for commercial and industrial customers also seems plausible. Accounts can be coded by size of billing demand, energy use and location. Such accounts could be given SIC codes or specifically designed codes to fit a given system's needs. The assembly of refined historical data such as this would be a valuable asset to the forecaster.

In the field of metering equipment there appear to be two devices which hold promise for the forecaster's use. One which has been on the market for nearly ten years is the magnetic tape recorder. It is currently used by a number of utilities primarily for load research activities. Several power systems already collect a great amount of detailed demand data in this way and create typical load curves for various classes of consumers. (See Ap-

pendix A–2 for one example.) The main advantage of this technique is the ease with which the demand data as recorded on magnetic tape can be translated on to either cards or tape suitable for computer processing. Since load data by appliance types and classes of customers can be of great significance in forecasting, this metering technique provides a relatively inexpensive and flexible method of producing the load information. More recently two dozen or more utilities have adapted these instruments for billing purposes. In these instances there does now exist the logical by-product of complete demand information which, if suitably arranged, could provide regular and current load characteristic data on a number of large power accounts. Such instruments also have equal adaptability for monitoring substation loads and are being used in this way by some utilities. Some are designed for four data tracks including time and are flexible enough to measure and record almost any type of electrical data required.

The other device, remote meter reading equipment, has not reached the economically practical stage of development for the normal metering requirements of most utilities although it now has several limited applications. If the device is perfected and is used throughout a utility system, the opportunity to acquire load data on a real-time basis would be available. Under these circumstances, for example, it would be possible to have immediate access to the demand and use characteristics of any or all segments of the total load.

2. Sources

There is already a wealth of useful data available to the industry on which to base forecasts. The sources and nature of this data have been fully described in Chapter IV. However, three further lines of development of data should lead to improved forecasting: greater timeliness, better localization and greater detail.

Currently, much data is available only long after its occurrence or only at very infrequent intervals. Such examples are the 9-month lag before the availability of the yearly data on Class A and B electric utilities and the decennial availability of much of the census data. Even today national economic data has impoved in timeliness. With direct access computer systems there is every expectation that data can be available substantially sooner. Internal utility data also are being reported and processed more quickly. In addition, the greater interest shown in national census data may mean more frequent censuses or better interpolative data between census. In either case, important population and appliance data would be improved.

One of the data problems facing each operating utility system is that much regional data are available only for areas which may not exactly coincide with the system's service boundaries. Many states and metropolitan areas are discussing or are in the early stages of implementing data banks. These would provide for the extraction of data by micro-area units in such a way that data could fit the geographic area of the system. In addition, in the field of weather data, the Weather Bureau has made available detail tapes and cards for their major weather reporting centers. It is not unlikely that more data, either from the Bureau, private weather forecasters or system sources will be available within the next few years. Such data would enable the electric utility forecaster to describe more fully the weather situation in his system.

Finally, because of the problems of manipulating, disseminating and comprehending masses of data, much detailed information has been left in original source documents. The Bureau of Census files are excellent examples. However, with computer processing it is possible to increase greatly the mass of data communicated, with the recipient extracting those pieces of importance to him. Also, a great deal of work has been done in the macro-economic area, detailing the functioning of the economy. These are becoming available as regular series of data. For example, the detail on the FRB Index of Industrial Production by two-digit SIC code is readily and currently available. (See Appendix D.)

It must be cautioned that with this outlook of improvement in data accessibility and timeliness there is still a substantial barrier to its use. Providing data is an expensive enough task in itself, publication probably being the least costly part. However, the cost of the subsequent re-organization and analysis of the data into useful forecasting information may be of several orders of magnitude greater. The availability of improved data will not automatically lead to improved forecasting without a significant investment by the forecaster.

D. Evaluation of Various Techniques

The applicability of specific forecasting techniques depends largely upon the load mix which the utility serves. Selection and development of

new techniques often occur when some significant shift in the load mix or emergence of a new load is recognized. A frequent practice in these instances is to isolate the new load, analyze it and forecast it separately. An outstanding, recent example of this is the emergence of summer cooling loads. Many utilities have analyzed these loads, studied load-weather relationships and revised forecasting techniques to include forecasts of the cooling load.

The techniques described in this chapter and in Appendices A and B all focus on the better understanding of the past load patterns. The technique may be one that stresses demography, or one that focuses on economic conditions or one that centers the attention on weather condition. If such an isolated factor critically affects a specific system's load pattern, then such a technique will help in understanding the past growth pattern.

However, none of these techniques provides for certainty in forecasting. The accuracy of the forecast is still dependent on the input the forecaster uses. The isolation of the more important load variables may help concentrate efforts on those areas of most importance.

Adopting a new forecasting method normally requires a significant expenditure to gather data, to analyze the data and to evaluate results. A new forecasting method will be tried only if the expected benefits of improved accuracy in forecasting will offset the costs. While such costs have been reduced by greater processing capabilities of computers and wider availability of data, they are still substantial.

E. Future Research Possibilities

1. Short-Term

Many improvements in short-term forecasting techniques are expected to continue to appear in the next few years. Several utilities report development of empirical formulae for automating short-term forecasts of hourly loads based on previous loads, weather conditions incurred, weather forecasts and other such variables.

On-line computer programs may be developed which will enable utilities to analyze and compare forecasts and actual load patterns. These comparative analyses could lead to the development of accurate simulation formulae representative of system characteristics under every load situation. On-line computer programs also may be devised for the purpose of utilizing frequency distribution and probability formulae in examination of load forecasting accuracy.

One of the more important requirements lies in the area of improved weather forecasting. This may well come about from increased utilization of weather aircraft, orbiting earth satellites and sophisticated modern weather instruments. This could permit electric utilities to improve the accuracy of their forecasts of day-to-day demand and energy requirements.

2. Intermediate and Long-Term

More research and development work is being directed to improving forecasting techniques for the intermediate and the long-term forecasting periods. Better utilization of computers will enable utilities to develop equations for reflecting more completely the significant factors affecting load. Any improvement in long-term weather and economic projections can be translated into more accurate load forecasts.

As new markets for electric power appear, means for measuring the likely impact and forecasting it should be evolved. These markets may lie in the transportation field (electric automobiles, mono-railways or other mass transportation media, not excluding electrified railways), in special industrial processes, in farm and home (robots), etc.

The foregoing indicates that intermediate and long-term system load characteristics will continue to change. The daily and seasonal demand and energy requirements as well as annual peak load growth characteristics probably will differ considerably from experiences of the past. Consequently, the electric utility industry will need to evolve new techniques that predict accurately these changes.

CHAPTER VII—CONCLUSIONS

The need for comprehensive study of the methodology of electric utility load forecasting has been increasingly recognized primarily due to two factors: greater volatility of load because of larger components of weather-sensitive load and lengthening lead times for planning and installing bulk power supply facilities. The Committee has attempted to assess the state of the art of load forecasting, to measure the extent of the need for better methods and techniques and to suggest improved means for meeting such needs. These studies have been limited to forecasting for bulk power supply planning.

Large capital investment is characteristic of the electric power industry. This results in capital charges being a large component of the total power cost. Therefore, to the extent feasible, systems strive to build only those facilities needed to serve load requirements fully and reliably. However, unrestricted use of power is taken for granted in our society, and accordingly it is essential that sufficient facilities be ready when needed. In meeting these dual objectives lies the importance of accurate load forecasting.

The analysis and investigation by this Committee have clearly indicated that no method exists which will provide absolute accuracy in forecasting. As in any forecasting, load forecasting can only lead to a well-informed, reasoned estimate as to the outcome of the future. Such reasoning is based upon a thorough understanding of the historical record, current experience and reasonable assumptions as to the future behavior of relevant parameters.

More sophisticated methods may reduce the areas of uncertainty in forecasting by allowing past phenomena to be understood more clearly. Application of new techniques by a number of systems has yielded encouraging results. Increased data handling capacity through mechanized means has led to progress in certain forecasting areas. Yet the basic problem of forecasting remains the same.

Also, the work of this Committee has shown that there is no method that is best for all systems. Rather, a method must be tailored to deal with the particular types of phenomena most important in influencing the load of the individual system.

Currently, many systems have seen or expect to see rapid increases in cooling and/or heating loads. These systems are concentrating on techniques which have as a common denominator the ability to excel in showing the relationship between load and weather variables. Some systems find that economic variables have the greatest impact on their load. These systems are experimenting with methods which focus most sharply on this particular aspect. Still others find variations in demographic variables to be the principal determinants of their load patterns; these systems employ methods most sensitive to demographic parameters.

It is perhaps in broadening the approach to forecasting that this report can make the greatest contribution. While a given phenomenon may be most critical to a given system, it is quite probable that others also may have an effect. By reviewing techniques employed by others, systems may find it possible to integrate several methods into one composite method for their own system. In a similar vein, those systems which have been concentrating on the impact of one set of variables may be encouraged to explore other variables long before they could otherwise sufficiently recognize their effect on the system's load data. The Committee hopes to open up new perspectives in load forecasting not otherwise readily available to the industry by listing in Chapter V all the basic methods reported to the Committee and discussing the pros and cons of each; by setting out in Chapter VI the several major new approaches which have been tried by some or which have had success in other fields; by discussing in some detail in the Appendices a number of quite different forecasting methods; and by compiling additional methods in the annotated bibliography.

Some of the more complex methods, supported by data not normally collected from utility systems, offer possibilities of improved forecasting. Con-

sideration of these should include a realistic appraisal of costs and benefits, that is, a weighing of the effect of possible improvement which might be achieved versus the additional cost of securing and processing such data and implementing such methods. Clearly, improved forecasting can be used to create substantial savings in capacity costs and operating efficiencies. However, a good deal of time is required to gather appropriate and meaningful data, to develop a method suitable for a specific system's characteristics and to gain confidence in the reliability of the results by thorough testing.

Many systems have been able to obtain reasonably good correlation between selected weather factors and total system loads. Use of such correlations of past data for forecasting future loads is impaired by the lack of certainty about future weather conditions. Forecasts of weather, even for a few days in the future, are not completely reliable. Predictions of weather conditions months or years ahead are even less reliable and generally available in only the broadest terms. Since extremes in weather conditions may cause a difference between actual and forecast demand of as much as 15%, it is desirable that due consideration be given in forecasting to the necessity of serving loads that occur during infrequent weather extremes, and that some method be found to factor weather conditions into the load forecast.

Two ways in which the Committee believes this problem may be solved are through the consideration of weather condition extremes and the derivation of probability data on weather conditions. The former can be used to forecast load conditions under weather extremes and the latter, the probabilities of various projected load levels. The most important application of such load forecasts is in the planning of generating capacity requirements. Such a probabilistic forecast can be combined with appropriate probability models of forced outages of generating units and maintenance schedules to compute needed capacity additions. Such load forecasts also can be used for the other functions discussed in this report.

The Committee has assessed some of the problems associated with the use of data used in forecasting, other than weather data. For example, economic, demographic or other data, external to the system, frequently do not match exactly the geographic area for which the forecast is being prepared. In addition, projections of such data made by various groups may differ substantially. This in turn would imply substantially different load forecasts depending on which specific projection of such data is employed. The Committee believes there will be steady improvement in external data availability, coverage and forecast accuracy. This will not relieve the load forecaster of the responsibility for selecting his data carefully and setting out clearly his assumptions on the expected conditions of the environment which underlie his forecast.

Data internal to the system are generally available to the load forecaster in detail sufficient to meet his requirements. However, there are instances of differences in data definition among systems that preclude precise aggregation of national or regional electric data. Efforts are underway within the industry to improve further the consistency of such data.

Forecasting methodology is a dynamic process. Most systems are examining and refining their forecasting methods on a continuing basis. Changes or planned changes in methods were mentioned by several systems in response to the Committee's questionnaire. Major revisions in methods have usually been precipitated by changes in basic load characteristics and/or load growth patterns. As new loads emerge or grow in importance further specialized techniques may be helpful but these can be discovered only empirically.

To summarize, incentives to adopt improved techniques include the larger load swings being experienced and the increasing economic pressures stemming from the need to maintain reliable, adequate service in the face of large investment requirements. Improvements in load analysis will come as the result of availability of better data and the application of appropriate new techniques. When applied with informed judgment to specific characteristics of particular power systems, these should help to overcome increasing difficulties of load forecasting, and thus contribute toward an optimum balance of costs and results in the planning and operation of electric power supply systems.

APPENDIX A
DESCRIPTIONS OF FORECASTING PRACTICES

This Appendix outlines the forecasting practices used by four systems represented on the Load Forecasting Methodology Committee: Tennessee Valley Authority, Pennsylvania Power & Light Company, Southern California Edison Company, and Commonwealth Edison Company. The technique developed by the Purdue Energy Research and Education Center (PEREC) for demand forecasting is also described. The conclusions in the papers are those of the authors, not the Committee.

APPENDIX A-1
DESCRIPTION OF FORECASTING PRACTICE
(Tennessee Valley Authority)

Summary

Forecasting is recognized as an important function in TVA and is carried out in detail. A variety of techniques are used. Where reasonable, two or more methods are used for each segment of the load. Within the Office of Power, the Division of Power Marketing prepares forecasts for from 1 month to 20 or 30 years in the future. The Division of Power System Operations prepares forecasts by hours for from 1 to 4 days ahead and weekly and monthly forecasts for 1 to several months ahead.

Uses of Forecasts

Forecasts are used by several organizations within the Office of Power for various purposes. The Division of Power Planning and Engineering uses load forecasts to plan new generation and transmission equipment. The Division of Power System Operations uses forecasts to plan generation needs hour by hour for the next 1 to 4 days, to plan efficient use of generation resources during the next year and beyond, and to coordinate scheduling of generator maintenance. The Fuels Planning Staff uses load and generation forecasts to estimate future fuel requirements. The Division of Power Marketing uses forecasts to estimate power sales revenues.

Characteristics of the System

TVA area loads peak in winter because the system serves one-half million electrically heated homes. The highest peak of calendar 1968, 15,266 MW, occurred in January. The lowest monthly peak of 1968, 10,738 MW, occurred in September. The system serves 2,000,000 ultimate consumers in an area of 80,000 square miles. Residential consumers account for 26% of the annual area consumption with business, industry, and outdoor lighting accounting for the rest.

Data Sources Used

A variety of data from outside of the organization are used. Some of these are listed below.

1. Population—Bureau of the Census, U.S. Department of Commerce.
2. Employment—Bureau of Labor Statistics, U.S. Department of Labor.
3. Appliance saturations—Appliance surveys; *Merchandising Week;* Bureau of the Census, U.S. Department of Commerce.
4. Building permits—Bureau of the Census, U.S. Department of Commerce.
5. Housing starts—Bureau of the Census, U.S. Department of Commerce.
6. Weather data—Environmental Science Services Administration, U.S. Department of Commerce.

7. Gas prices—American Gas Association; Moore Publishing Company.
8. Business indicators—*Business Conditions Digest*, Bureau of the Census, U.S. Department of Commerce.
9. Use characteristics of appliances—GE, Westinghouse, EEI, and published studies.

Some of the above data are used in calculations. For example population per customer is calculated for past years. After customers are extrapolated, population forecasts are used to compute future population per meter. This is reviewed in light of past trends as a check on the reasonableness of customer projections. Other data are used without calculations to explain past loads. For example, slight variation in the growth of energy may be explained by a marked change from year to year in building permits and housing starts. Most of these data are used in occasional studies or as background information.

Data from within the utility which are used in forecasting are listed below:

1. Standard load data (hourly loads; monthly energy sales and customers by classes of service; losses; daily, monthly, seasonal, and annual peaks) power bills; log sheets; meter tapes.
2. Contract demands—customer contracts.
3. Characteristics of special loads—special metering and coding of specific loads, such as electric heating customers with resistance heating or with heat pumps.
4. Results of area appliance promotion programs—Division of Power Marketing.
5. Planned new loads or planned expansions of existing loads—industrial announcements in newspapers, magazines, and local publications, and contacts with community leaders and industry officials—Division of Power Marketing.

Analytical Steps Prior to Forecasting

Considerable adjustment of data and analytical work is completed prior to actual forecasting. Illustrations of this work are given below:

1. Written general assumptions are prepared for the next 5 years. These include assumptions concerning business cycles, how the region will share in national growth, the effect of peace in Vietnam on specific defense loads and on the economy of the region generally, and the effect of rate changes.
2. Weather data and other information are used in evaluating actual loads versus forecasts.
3. Historical relationships are updated and studied. Among these are the number of customers
with demands less than 50 KW per 1,000 residential customers and industrial energy per residential customer. These and other relationships are used after preliminary

TABLE 4

Customers, Population, Households, and Jobs, 170 Power Service Counties, Calendar Year Data

Calendar year	Residential customer (millions)	Population July 1 (millions)	Household July 1 (millions)	Jobs (millions)	Population as percent of United States	Household as percent of United States	Jobs as percent of United States	Population per household	Population per job	Population per customer	Household per customer	Jobs per household	Jobs per customer
1940.....	.33	4.72	1.14	1.51	3.58	3.25	3.18	4.15	3.13	14.37	3.46	1.33	4.59
1945.....	.51	4.45	1.10	1.64	3.36	3.06	3.11	4.05	2.71	8.65	2.14	1.50	3.19
1950.....	.97	5.06	1.33	1.70	3.32	3.05	2.85	3.80	2.97	5.21	1.37	1.28	1.75
1955.....	1.23	5.07	1.37	1.83	3.06	2.86	2.91	3.70	2.77	4.13	1.13	1.33	1.49
1960.....	1.42	5.35	1.48	1.79	2.96	2.81	2.69	3.61	2.99	3.77	1.05	1.20	1.26
1965.....	1.64	5.63	1.63	2.03	2.89	2.85	2.81	3.44	2.78	3.44	1.00	1.24	1.24
1970.....	1.82	6.18	1.82	2.31	3.00	2.92	2.90	3.39	2.67	3.39	1.00	1.27	1.27
1972.....	1.90	6.39	1.90	2.40	3.03	2.95	2.90	3.36	2.67	3.36	1.00	1.26	1.26
United States													
1940...............		132.0	34.9	47.5	....	....	....	3.78	2.78	....	....	1.36	....
1950.....	37.5	151.2	43.6	59.7	....	....	....	3.49	2.53	4,03	1.16	1.37	1.59
1960.....	51.3	180.0	52.6	66.4	....	....	....	3.42	2.70	3,51	1.03	1.27	1.30
1965.....	57.4	194.6	57.3	72.2	....	....	....	3.40	2.70	3,39	1.00	1.26	1.26
1970.....	62.5	206.0	62.4	79.7	....	....	....	3.30	2.58	3.30	1.00	1.28	1.28
1972.....	64.8	211.1	64.6	82.7	....	....	....	3.27	2.55	3.26	1.00	1.28	1.28

projections are made as a check of reasonableness and to insure internal consistency between the various load segments of the forecast.

4. Special studies are updated or carried out. For example, the future regional share of the national output of primary aluminum is studied in terms of the historical regional share, recent additions of new reduction capacity by regions and companies, and announcements of planned new capacity. The results of this study are used with predictions of national capacity or output to obtain a band of likely future regional capacity. This study is used later when loads of the four individual aluminum producers of the area are predicted.
5. Load data are adjusted. For example, peaks are adjusted to normal minimum or maximum temperatures. Residential energy is adjusted to normal heating degree days. All energy series are adjusted for significant metering errors or variation in billing cycles. All energy series with seasonal patterns are seasonally adjusted by formal time series analysis.

Forecasting Steps

1. Short-Term Forecasting

Hour-to-hour and day-to-day forecasts are prepared by adding expected changes to the most recent similar load. Expected changes may include normal differences between Saturday, Sunday, and weekday loads, known large industrial load changes, and weather forecasts which are used with load-weather relationships. Load-temperature relationships are established by plotting load versus temperature at selected hours. Other weather elements, such as wind, sky-cover, precipitation, humidity, antecedent weather conditions, and air mass movements, are analyzed and applied.

Weekly forecasts are based on present weather conditions converging to normal weather conditions for the period of the forecast, usually 4 to 6 weeks in the future.

Weekly peak forecasts for longer periods are based on monthly forecasts as developed below. One week in the month is designated as having the monthly peak. For example, the last week in November is more likely to have the monthly peak than prior weeks because it is normally colder and days are shorter in the last week. Expected peak demands of other weeks are computed from the monthly peak on the basis of normal temperature differences and historical patterns from week to week. Weekly energy is predicted similarly using monthly energy forecasts.

TABLE 5

Residential Yearly Average Use

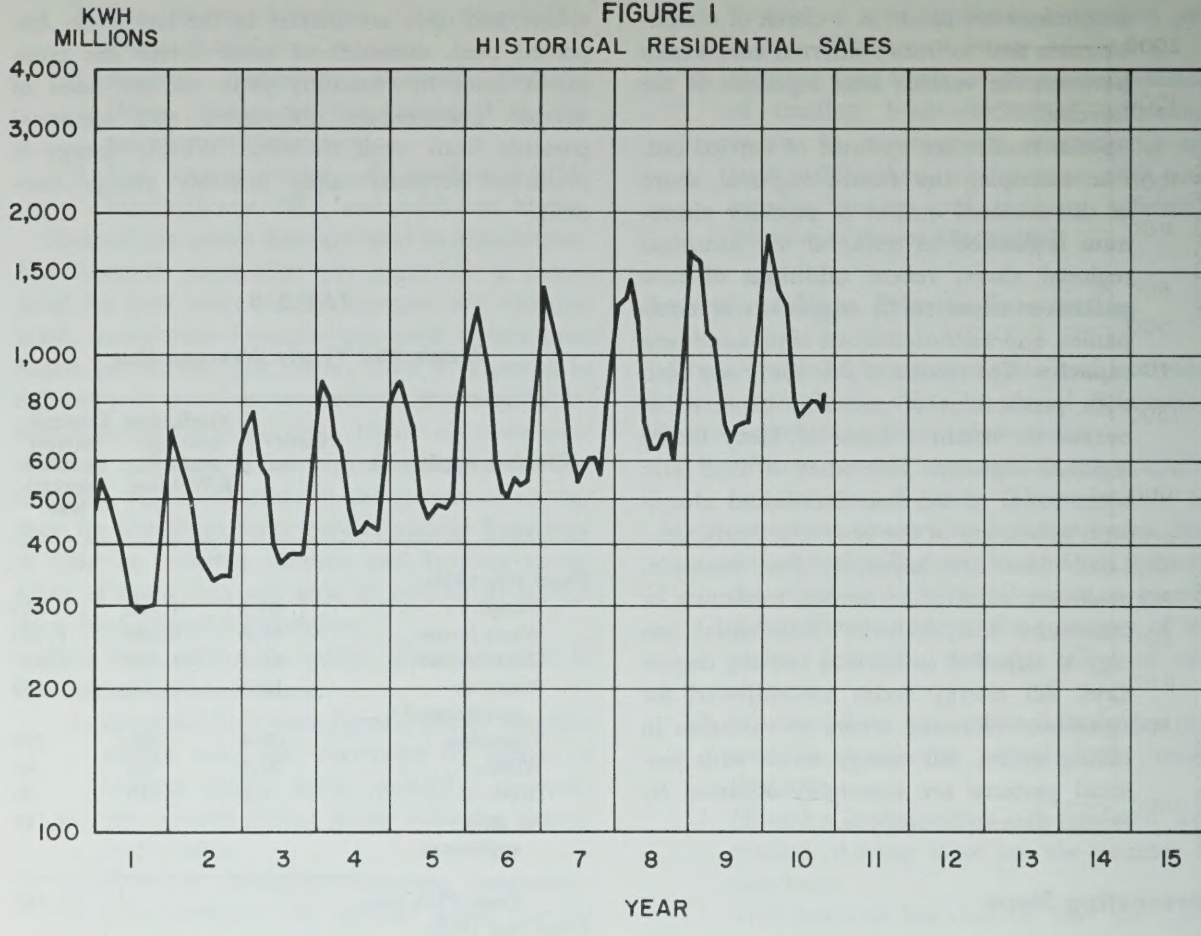
Electric appliance	Saturation	Appliance average annual KWH use	Contribution to total average use
Fiscal year 1958:			
Range	60.4	1,350	815
Water heater	41.0	4,380	1,795
Electric heat	15.7	[1]11,790	1,850
Room air conditioner[2]	12.3	1,300	160
Television	69.4	400	275
Washer	70.8	65	45
Dryer	7.9	1,110	90
All other appliances			2,159
Total TVA area			7,189
Fiscal year 1963:			
Range	72.7	1,350	980
Water heater	56.6	4,770	2,700
Electric heat	22.4	[1]11,620	2,605
Room air conditioner[2]	23.2	1,375	320
Television	88.7	400	355
Washer	82.4	70	55
Dryer	16.7	1,210	200
All other appliances			2,263
Total TVA area			9,478
Fiscal year 1968:			
Range	79.0	1,350	1,065
Water heater	69.0	5,100	3,520
Electric heat	29.1	[1]11,855	3,450
Room air conditioner[2]	33.5	1,580	530
Television	98.0	400	390
Washer	89.0	75	65
Dryer	32.5	1,320	430
All other appliances			3,218
Total TVA area			12,668

[1] Average use with normal heating degree-days is 10,000 KWH.

[2] Excludes central air conditioning.

FIGURE I

HISTORICAL RESIDENTIAL SALES



2. Intermediate Term—4 to 6 years

Loads are grouped for analysis by classes of consumers. Business and industry consumers for which demands are available are further grouped by size of demand.

There are about 120 business and industry loads with demands of 5,000 KW or more. These include large aluminum producers, chemical industries, ferro-alloy plants, and Federal establishments including AEC. Predictions of these loads are based on contract demands, historical loads, stated plans of the consumer, and future markets for products. To provide for growth beyond stated plans, amounts of undesignated power are added to known loads. The amounts added are based on past trends, inquiries for power, analysis of power use by industry groups, and study of factors influencing industrial development.

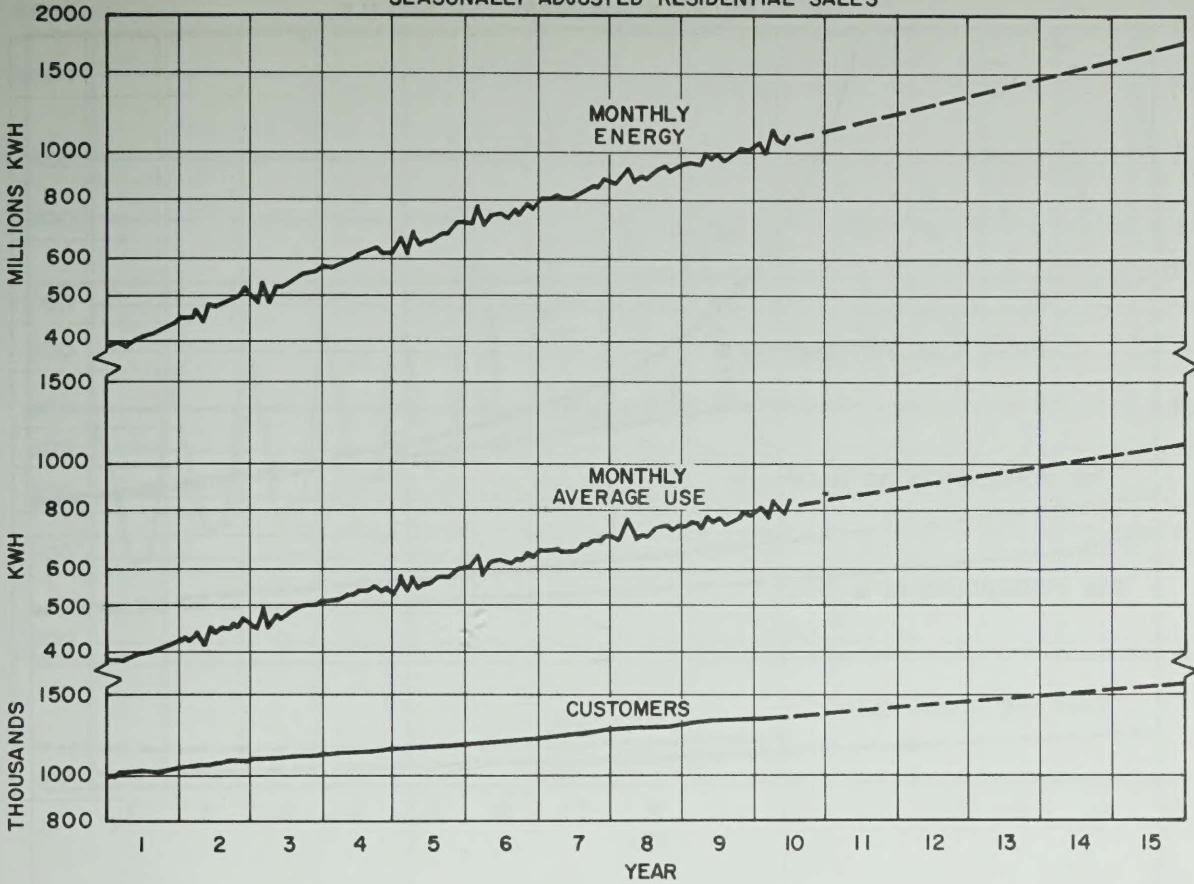
Loads under 5,000 KW are divided into seven geographic areas: five large cities, a group of small municipalities, and a group of cooperatives. Loads for each of these seven geographic areas are divided into five classes of service. These classes are home and farm consumers, commercial and industrial under 50 KW, commercial and industrial 50 to 1,000 KW, commercial and industrial 1,000 to 5,000 KW and outdoor lighting.

Each of the 35 energy series with demands under 5,000 KW are analyzed in detail and projected. Analysis includes adjustment to normal weather conditions for weather sensitive series, seasonal adjustment, study of average uses and customers which support the energy, and study of underlying growth factors. Where reasonable, two or more methods are used for forecasting each series. Forecasting of residential sales is discussed below as an illustration of the use of several methods in forecasting.

Forecasting of Residential Sales

Forecasts of residential sales are based on projections of electric heating and appliance saturations, demographic factors, jobs, relationship of residential customers to commercial and industrial customers and sales, and percent of U.S. sales as

FIGURE 2
SEASONALLY ADJUSTED RESIDENTIAL SALES



well as trend projections. Historical sales data as shown in Figure 1 are adjusted for abnormal weather and seasonally adjusted as shown at the top of Figure 2. Customers are divided into the treated sales data to obtain a trend of average use as shown in the middle of Figure 2. The sales trend is extrapolated using visual methods with fitted curves used from time to time. The average use and customers are extrapolated also. These two extrapolations are multiplied to compare with the above sales extrapolation.

The customer extrapolation is forecast by an alternate method as a check on the reasonableness of the extrapolation. Forecasts of U.S. population, customers, households, and jobs are used with projected ratios of the TVA area to the U.S. as shown in Figure 3 and Table 4. The resulting customer forecast is compared with the customer extrapolation. Differences are resolved by re-study and judgment.

The average use extrapolation is verified by an alternate method also. Projected saturations for 15 appliances are multiplied by estimates of annual energy uses of the various appliances. Each product is the contribution of that appliance to total average use. The sum of these products is the forecast of average use. Table 5 is an abbreviated illustration of this method. Any deviation difference from the average use extrapolation is resolved by re-study and judgment.

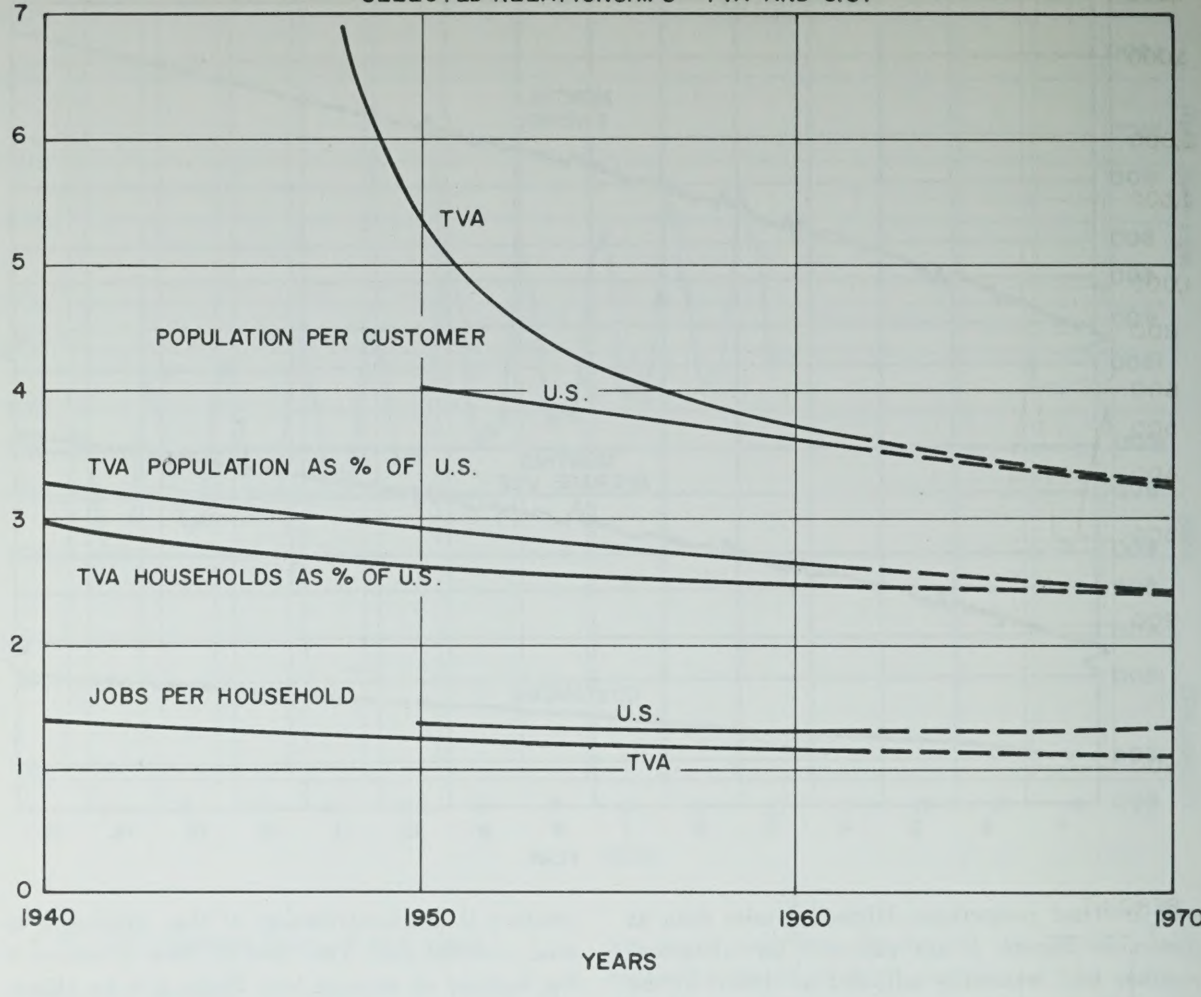
The original sales extrapolation may be revised on the basis of revisions of average use and customer projections. Sales seasonal indexes are extrapolated and multiplied by corresponding values of the final sales trend extrapolation to obtain the residential monthly sales forecast as shown in Figure 6. As a final check, customers and sales may be calculated as a percent of the U.S. data as shown in Figure 7.

The Total Forecast

Projections of kilowatt-hour trends by classes of service are added for each of the seven geographic areas. Estimates of distribution losses and projections of seasonal indexes and load factors are used in computing energy requirements and peaks by

FIGURE 3

SELECTED RELATIONSHIPS - TVA AND U.S.



months for each of the seven geographic areas. This process is illustrated in Figure 8. The system peak forecast is obtained by adding the predicted peaks of loads over 5,000 KW, the seven geographic areas, estimates of system transmission losses, and the effect of diversity. Energy forecasts by months are obtained similarly. These results are checked by predicting peaks from weather adjusted historical peaks and by projecting annual energy requirements from adjusted historical data.

3. Long-Term Forecasting—10 to 30 years

Long-term forecasts are essentially extrapolations from historical annual summer and winter peaks and the first 5 years of forecast as described above. The historical relationship between these seasonal peaks is reviewed in light of probable future growth of cooling and heating loads to maintain a reasonable relationship in the forecast. Peak demands for the other 10 months are projected and controlled by relating them appropriately to either the winter peak or the summer peak. Energy forecasts are obtained by projection of load factors.

Probability of Deviations

Official peak and energy forecasts are based on normal extreme temperatures and degree days. The probability of the forecast being exceeded is 50%. Peak forecasts under a range of probabilities are computed for use in power supply planning. Probabilities of peaks are based on the probabilities of maximum or minimum temperatures for a given month. For example, a winter month peak with a 50% probability of being exceeded increases as the probability of the peak being exceeded drops to 10% at minimum temperatures 14 degrees colder than the normal minimum temperature.

FIGURE 6

RESIDENTIAL SALES WITH FORECAST

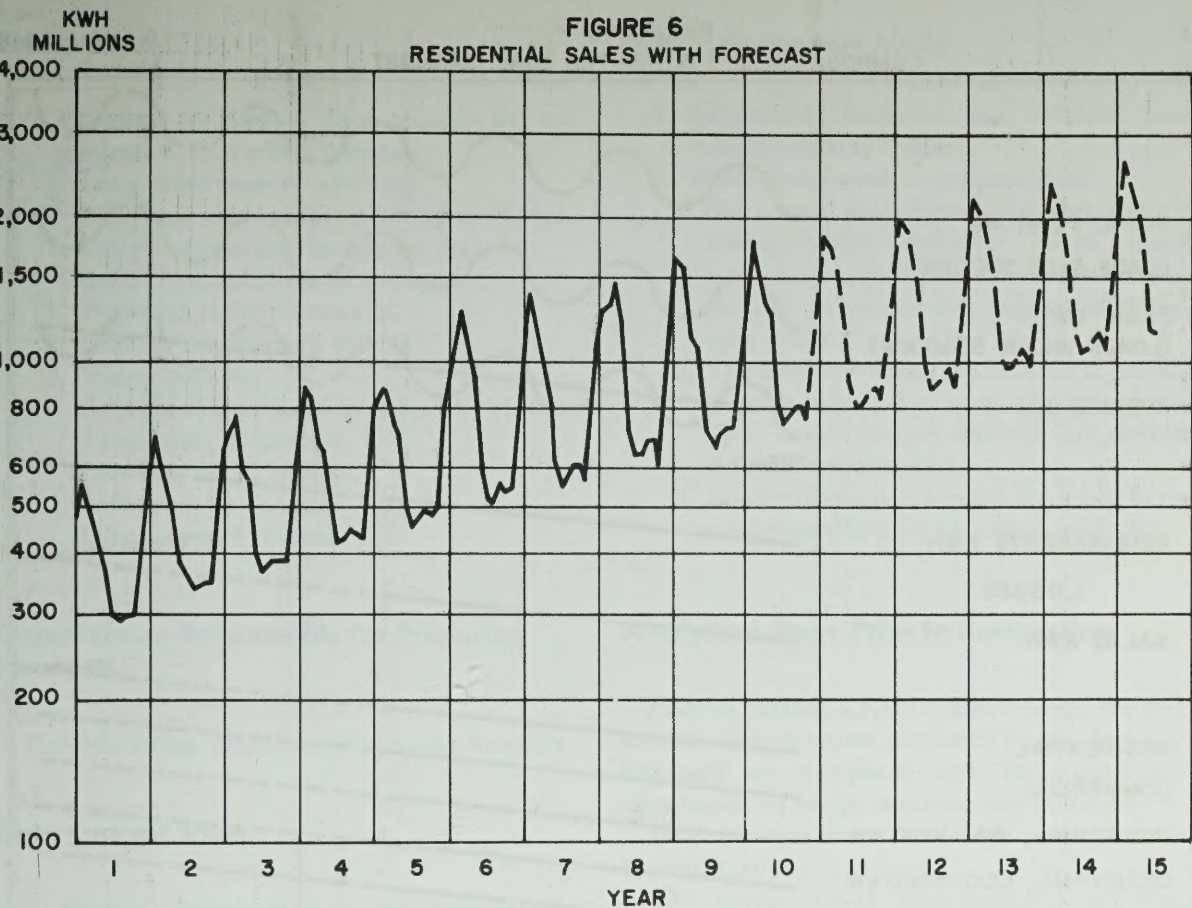


FIGURE 7

RESIDENTIAL SALES AS PERCENT OF U.S.

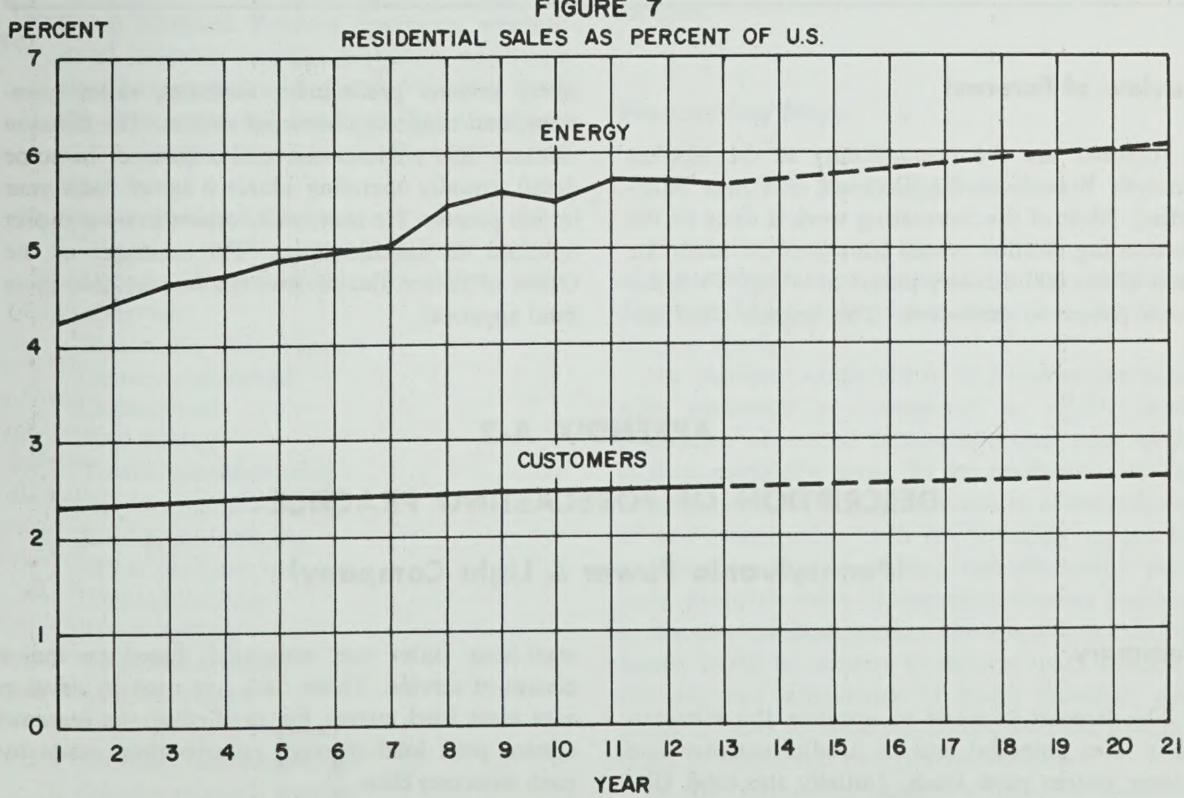
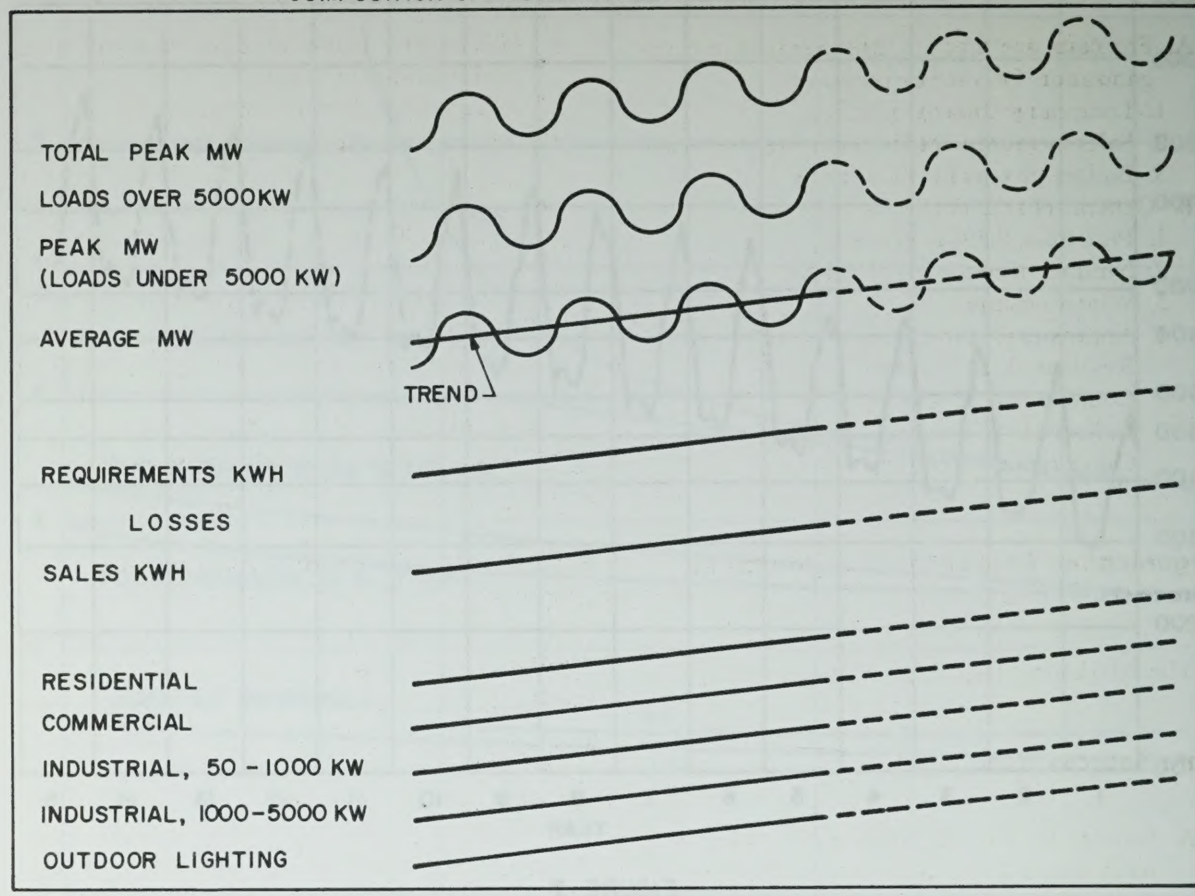


FIGURE 8
COMPOSITION OF DISTRIBUTOR LOAD FORECAST



Review of Forecast

Forecasts are the responsibility of the Market Analysis Branch of the Division of Power Marketing. Most of the forecasting work is done in the Forecasting Section which also predicts loads for each of the 600 delivery points at which TVA delivers power to customers. The branch chief actively reviews preliminary forecasts, raises questions, and suggests additional studies. The division director also reviews the entire forecast in some detail, usually spending about 8 hours each year in this process. He may invite others to offer expert opinions on specific items. The manager of the Office of Power also reviews the forecast and gives final approval.

APPENDIX A-2

DESCRIPTION OF FORECASTING PRACTICE

(Pennsylvania Power & Light Company)

Summary

The forecast is made to appraise the kilowatt-hour sales potential and to predict summer and winter system peak loads. Initially the total kilowatt-hour sales are estimated based on major classes of service. These data are used to develop rate class load curves for predicting the seasonal system peak load through contributions made by each customer class.

Background

A. Forecasts are used in three areas in the organization for various purposes:
1. Long range capacity planning.
2. Sales measurement for operating territories.
3. Budget process for the coming year.

B. General characteristics of the system:
1. Peak load, 2,500 megawatts.
2. Number of customers, 810,000.
3. Winter peaking.
4. Approximate proportion of load by classes:
Residential, 34 percent.
Commercial, 21 percent.
Industrial, 41 percent.
Other types, 4 percent.

Organization Responsible for Preparing Forecasts

The Marketing Department prepares forecasts.

Data Sources Used

A. Sources outside of Company—Federal Reserve Board Index of Industrial Production, Gross National Product Forecasts, weather data, industry vacation schedules, appliance use characteristics obtained primarily from the Edison Electric Institute. The Company also estimates service area population and labor force.

B. Sources inside of Company:
1. Historic trend of system peak load.
2. Historical trends of sales by major classes of service:
Electrically heated homes
General residential
Commercial
Coal mining
Textile manufacturing
Cement manufacturing
Steel manufacturing
Metal products industry
General industry
Street lighting
Electrical railways
Sales for resale
3. Load research studies.
4. Monthly bill frequencies.
5. Market research studies.

Data Adjustments Made

A. Adjustments made to data received from outside company: None.

B. Adjustments made to company data:
1. Sales data are adjusted for variations in billing cycles, reporting errors, major customer reclassifications, strikes, and other possible influences that might distort true sales trends.
2. The company data are processed to provide suitable inputs for load research studies from which sample statistics are derived for each customer class.
3. Load curves are corrected for losses to the net generation level for a given peak day.

Analytical Steps Prior to Forecasting

Prior to making a KWH sales forecast, the final annual sales estimates prepared by the key sales personnel are compared with the quantitative sales trends by major customer classifications.

The sales trends are formulated and computed by Staff Analysts.

The annual KWH sales estimates are summarized by rate schedules and are used in the load forecast.

Forecasting Steps

A. The Energy Forecast

The load forecasting starts with an appraisal of kilowatthour sales potentials and probabilities. This is done by major classes of service. (See Data Sources Used.)

For the short range (12 to 18 months) key local sales personnel are requested to supply their evaluation of several factors affecting sales levels in their particular areas. In the residential market an attempt is made to get a measure of the volume of new construction both single family units and apartments, vacancy rates, redevelopment projects, probable share of the space heating business in the new dwelling market, the number of existing homes likely to convert to electric space heating, the use and acceptance of major domestic appliances, sales to farm customers, and the general trend of residential energy requirements.

In the commercial market a survey is made of

the probable volume of new commercial construction, the probable operating levels of the larger accounts, significant new load additions or losses and the use and acceptance of electric space heating.

Key firms are queried in the industrial sector to get first hand information on estimated operating levels and a general "feel" for future local business conditions; specific new accounts, large load additions or losses are identified; and a collective estimate is made for all of the "smaller" customers. This method is followed for each of the six industrial categories itemized under "Data Sources Used."

The above kilowatthour sales data are reviewed and compared with an independent analysis of sales trends prepared by staff analysts. The final sales estimates reflect a blending of these two studies.

The initial estimates are for an annual period. When these become final, a further breakdown is made for each class of customer to develop the estimated annual sales for each rate schedule within the class. Annual sales estimates by rate schedules are then summarized. These statistics are used primarily in the load forecasting process as described in part B below. Monthly sales estimates are then made recognizing such variables as weather, hours of daylight, industry vacation schedules and meter reading schedules.

The long-range sales estimates are also made for the classification of accounts as previously mentioned. The various elements influencing sales growth within each class continue to be the major guides in developing the forecast. At this point in the process local personnel involvement diminishes except to provide overall appraisals of various markets and advice on specifically known future additions and losses in the commercial and industrial sectors. A forecast is also made of the service area population and labor forces. Historical trends of sales are also employed. An overall judgment is then applied to each class, recognizing the various factors briefly described here. At the present time, little or no attempt has been made to correlate sales forecasts with forecasts of national or regional business indicators.

B. The Load Forecast

The load forecasting technique discussed here was developed for the primary purpose of predicting summer and winter system peak loads through the contribution made by each class of service to that peak. The term "class" as used here means all customers served under the same rate schedule.

The fundamental concept behind this technique is the development of the load characteristics for at least the summer and winter periods for each of the major classes of customers. Other essential data consist largely of monthly KWH and hours-use-of-demand bill frequency distributions and historical monthly energy sales for each class.

Load research studies of residential and other customer classes whose billing meters are of the watt-hour type are conducted using stratified random samples of customers within KWH ranges. The sample selections within KWH ranges are then monitored with load research meters. These test data are used to develop a typical daily load curve for each KWH stratum. Similar daily load curves for general service sample customers (up to 5,000 KW with demand meter billing) are assembled in load factor ranges within each rate class. Larger customers (over 5,000 KW) are studied on an individual basis. These studies provide sample statistics for each segment of the electric utility customers. The statistical data are applied to the universe, resulting in a universe rate class load curve. The universe is derived from the usual bill frequency and hours-use distributions prepared for the rate department's price studies.

An estimated universe load of each rate class, at the sales level, is prepared for each day of seasonal system peaks for the past five years. The development of the rate class load curves varies slightly from class to class, but in each case the universe customers are segregated by the same demand or energy use ranges as used in the respective load survey sample. The relevant load characteristic is applied to each class subdivision and the results are totalized to produce a load curve for each customer class. (See Figure 9.) Class load curves corrected for losses are then totaled hour-by-hour to calculate the estimated system daily load curve for a particular peak day. Past studies have produced estimated system loads consistently comparable to actual conditions. (See Figure 10.)

Future class peaks are estimated in the following manner. Correlating past estimates of rate class contributions to system peak with annual KWH sales of that class reveals a high degree of association between these two variables. (See Figure 11 for General Residential Service.) It has been

FIGURE 9
PENNSYLVANIA POWER & LIGHT COMPANY
COMPONENTS OF GENERAL RESIDENTIAL CLASS LOAD
WINTER

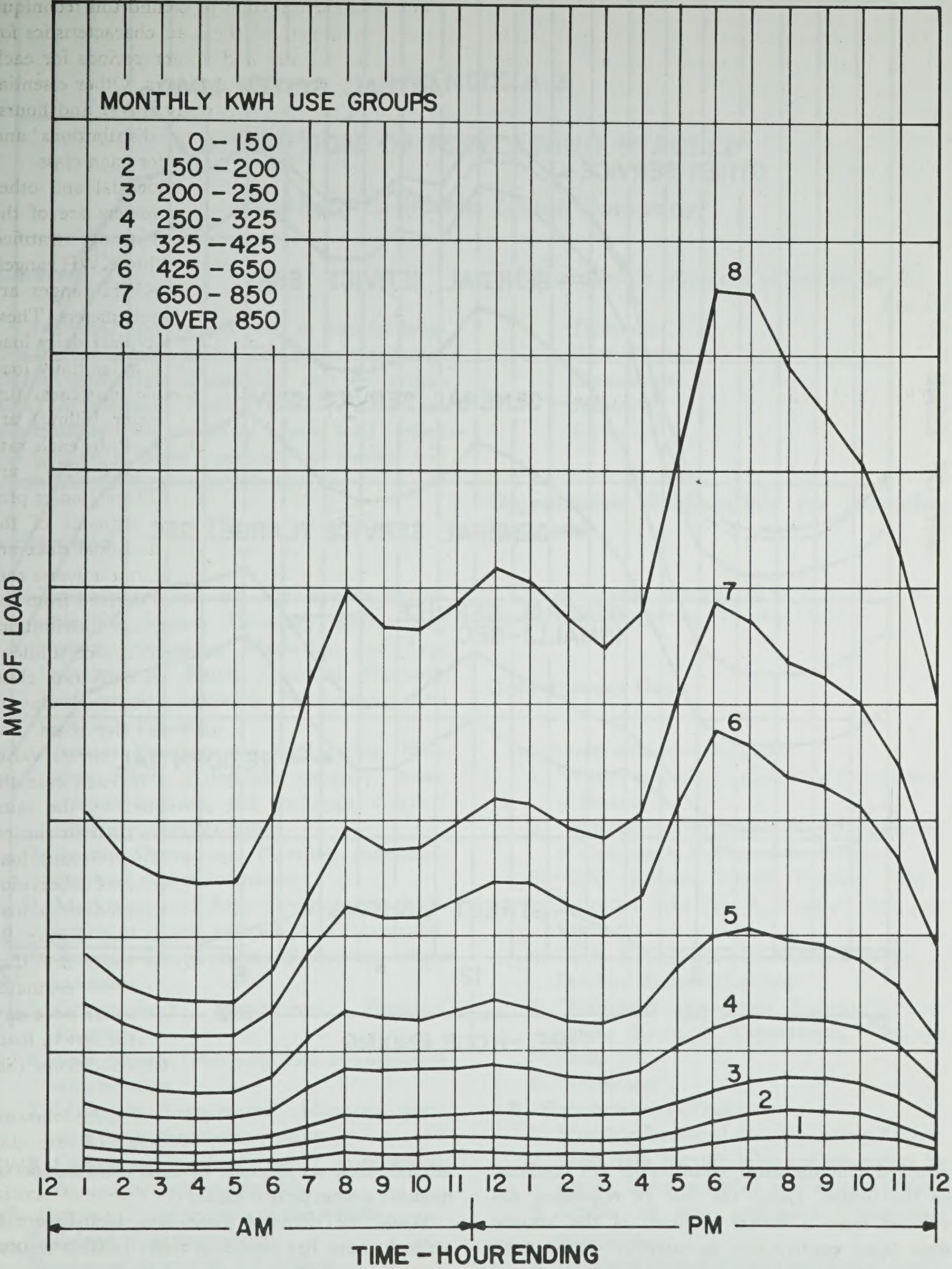
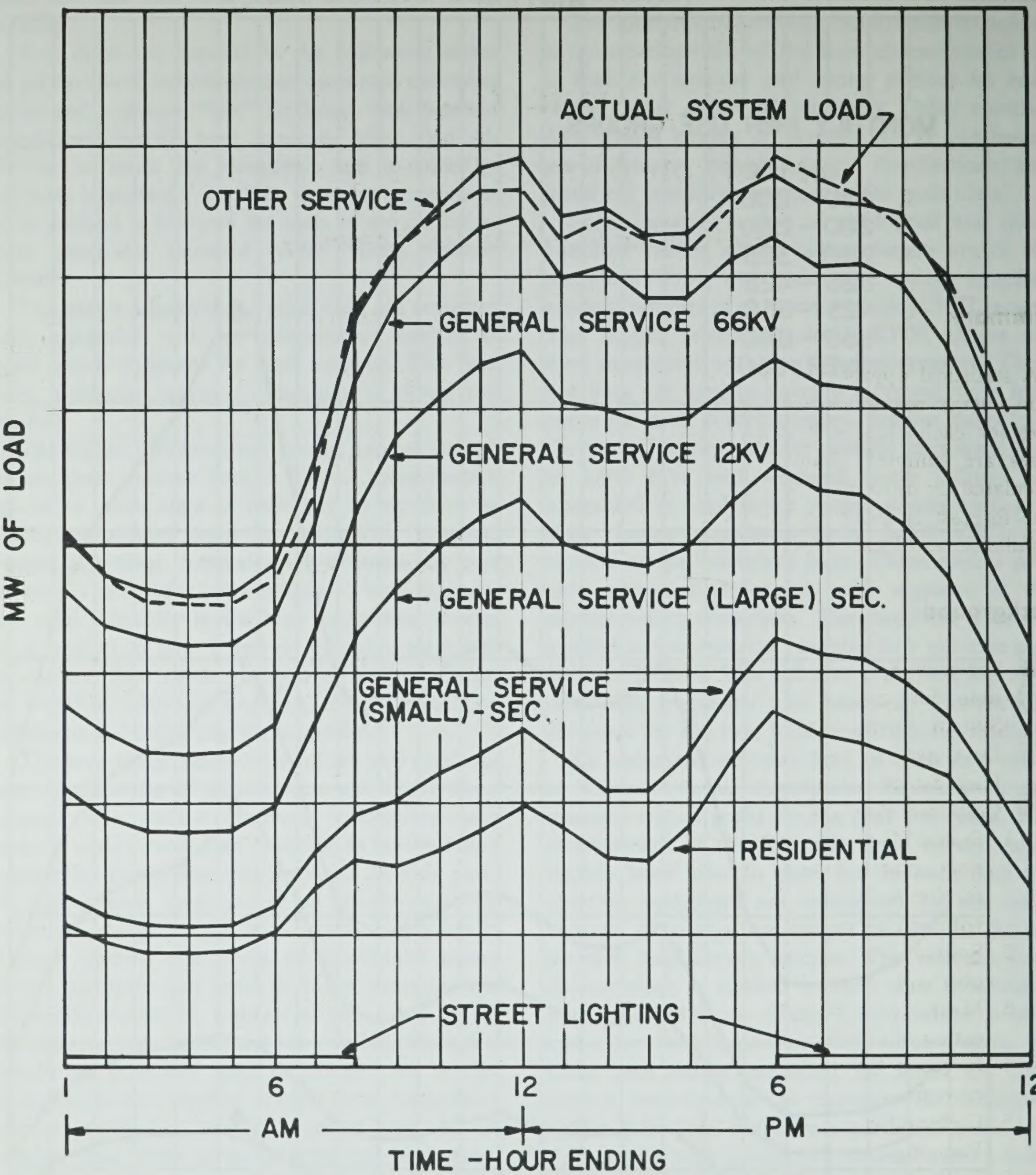


FIGURE 10
PENNSYLVANIA POWER AND LIGHT COMPANY
MAJOR COMPONENTS OF SYSTEM LOAD



assumed that the same relationship will continue in the future. Using the line of regression developed from a scatter diagram of the historic data (class contribution to monthly system peak vs. class annual KWH sales) and the forecasted annual sales, an estimate of class contribution to monthly system peak is made.

While the demand forecasting technique described above has produced fairly reliable results, there is currently underway a study which will

supersede the peak contribution/annual sales relationship with a forecast of future bill frequency distributions based on sales estimates by months. With such data available past load characteristics could be applied to future frequencies directly. Also under development is the determination of the effects of severe temperature/weather conditions on seasonal loads.

APPENDIX A-3

DESCRIPTION OF FORECASTING PRACTICE

(Southern California Edison Company)

Summary

A statistical approach is used to forecast long-term energy requirements. The projected energy sales for each class of customer and the system losses are summed. Annual peak demands are calculated by using estimated annual load factors. The forecast is based essentially on service area population and local economic indicators.

Background

A. Forecasts are used by organizations responsible for System Planning, Engineering, System Operations, Marketing and Area Development, Rates, Financial Planning, Fuel Supply, Materials Procurement, and Corporate Planning.
  1. System Planning and Engineering. Planning future generation capacity, transmission facilities, and exchange of power with neighboring utilities.
  2. System Operations. Planning generation overhaul and maintenance.
  3. Marketing and Area Development. Indication of growth rate which is anticipated.
  4. Revenue Requirements. Estimating future revenues.
  5. Comptroller's Department. Financial Planning.
  6. Fuel Supply. Planning fuel requirements with vendors.
  7. Materials Procurement. Advanced planning for products with vendors.
  8. Corporate Planning. Impact on organization, manpower and facilities.

B. General Characteristics of the system.
  Peak load, 8100 megawatts.
  Number of customers, 2.5 million.

  Approximate proportion of load by classes:

	Percent
Domestic	24
Agriculture	3
Commercial	21
Industrial	35
Other types	17

Organization Responsibile for Preparing Forecasts

The long-range forecast (10 to 30 years) is prepared by the Corporate Planning Division.

Data Sources Used

A. Sources outside of Company.
  1. "State Population", California Department of Finance.
  2. "Population Estimates", U.S. Department of Commerce, Bureau of the Census.
  3. "GNP Growth Trends Through 1980", Research Brief No. 4, Stanford Research Institute.
  4. "U.S. Birth Rates", Research Brief No. 5, Stanford Research Institute.
  5. "Estimated Population Increase", Economic Research Department, National Bank.
  6. "Predicasts".

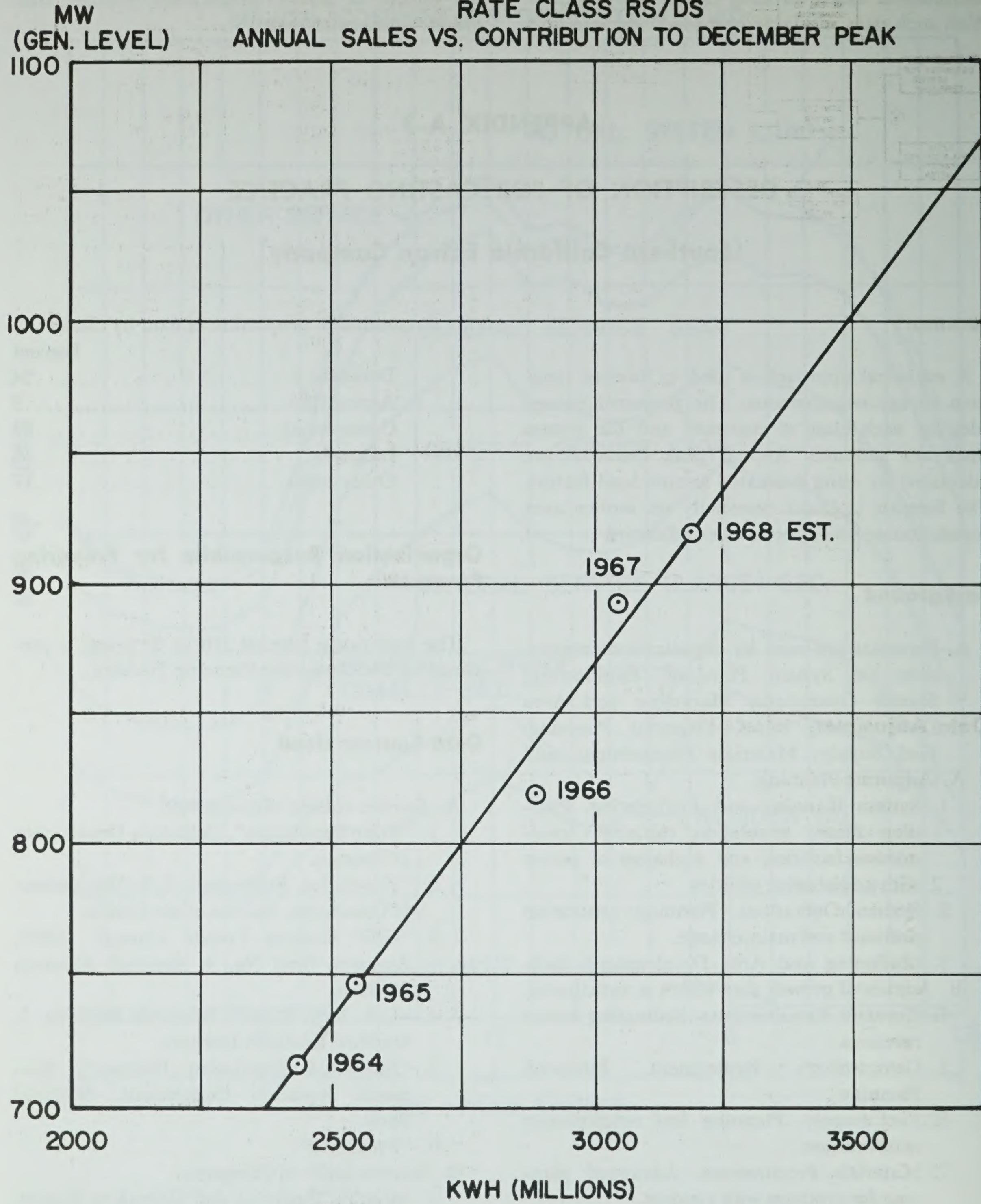
B. Sources inside of Company.
  1. Monthly Financial and Operating Report.
  2. Load data (energy sales and customers by classes, losses, monthly and annual peaks).
  3. Results of area appliance promotional programs.
  4. Characteristics of isolated and special loads.

FIGURE II

PEAK LOAD FORECASTING

RATE CLASS RS/DS

ANNUAL SALES VS. CONTRIBUTION TO DECEMBER PEAK



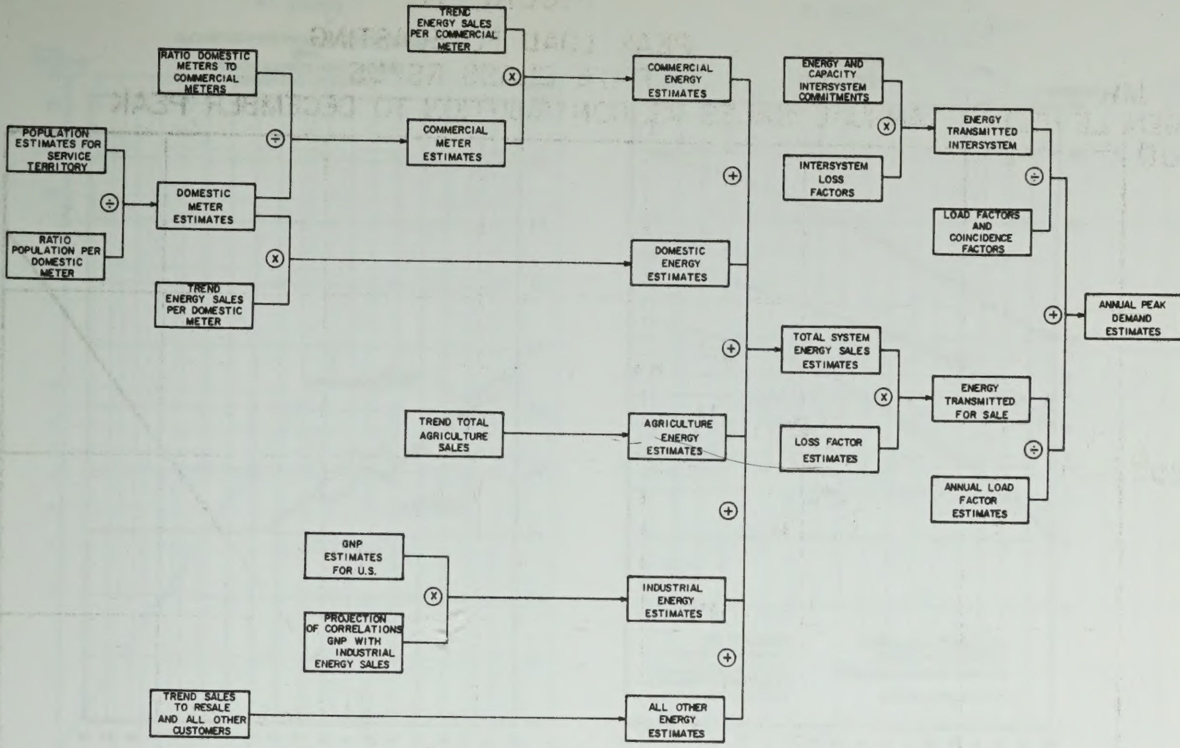


FIGURE 12

MAJOR COMPONENTS OF SYSTEM PEAK DEMAND ESTIMATES

Data Adjustments Made

A. Adjustments made to data received from outside of Company.
   1. Population forecasts by county are adjusted to include only service area population.
   2. Gross National Product is converted to 1958 dollars to eliminate the effects of inflation before it is used in a regression and correlation analysis.

B. Adjustments made to Company data.
   1. Agricultural kilowatthour sales estimates are based on "normal" rainfall conditions (average rainfall over the past fifty years is considered normal).
   2. Total losses are estimated as a percent of kilowatthours transmitted.
   3. Contractual agreements to serve loads outside the service area are estimated separately and added to the total energy requirements and peak demands.
   4. An average load factor is computed using recorded kilowatthours transmitted and recorded annual peak demand for the system.

Analytical Steps Prior to Forecasting

1. Historical data noted under "Data Sources Used" are reviewed and updated.
2. Special studies, primarily regression and correlation analyses, are updated.
3. Applicable computer trend programs are updated.

Forecast Steps

Long-term energy requirements are determined by the Corporate Planning Division by summing the projected kilowatthour sales for each revenue class of customer and the estimated total system losses. Annual peak demands are calculated using estimated annual load factors.

The procedure used to determine the long-range forecast of energy requirements and peak demands is outlined below and diagrammed in Figure 12.

Population.—Adjusted population forecasts are the starting point for domestic and commercial class estimates. (Figure 13)

FIGURE 13

POPULATION
AT YEAR END

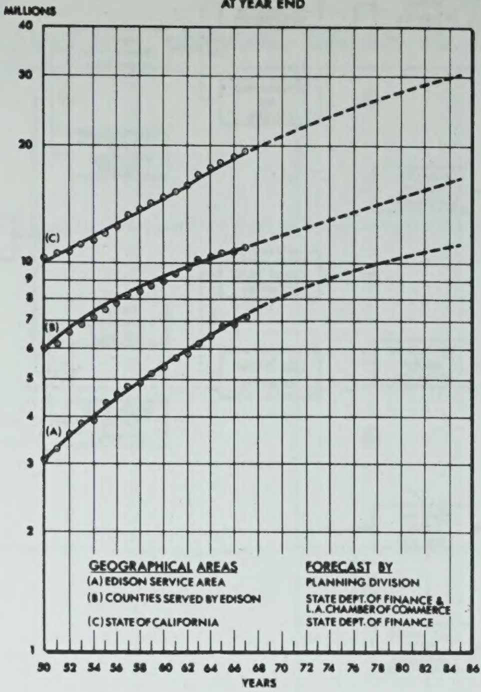


FIGURE 14

NATIONAL POPULATION PER HOUSEHOLD
AND
EDISON AREA POPULATION PER
DOMESTIC CUSTOMER

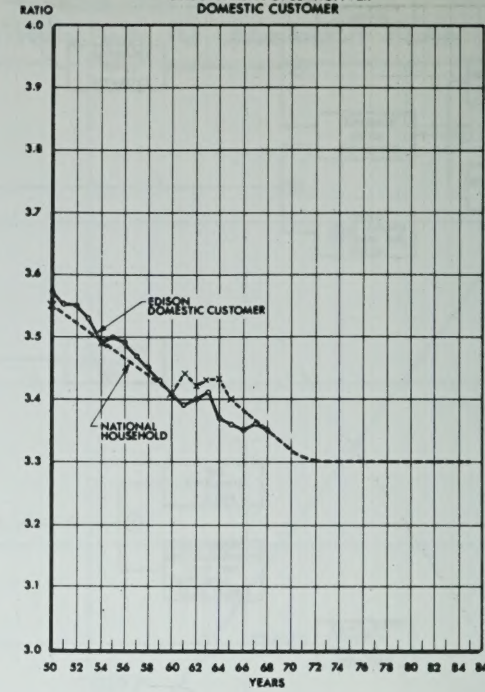


FIGURE 15

DOMESTIC CUSTOMERS
AT YEAR END

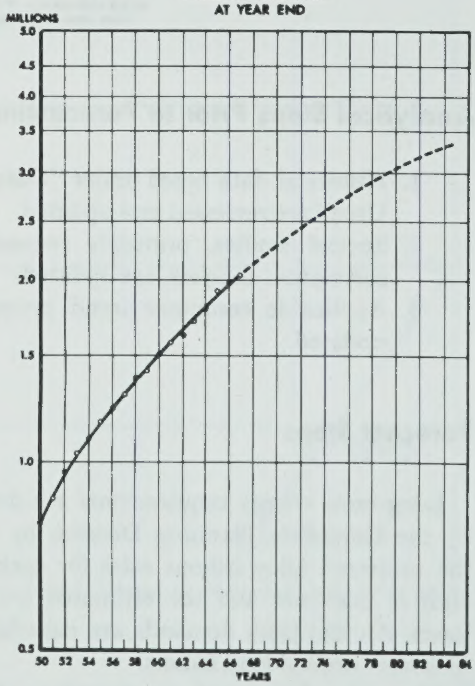


FIGURE 16

SALES PER DOMESTIC CUSTOMER
AT YEAR END

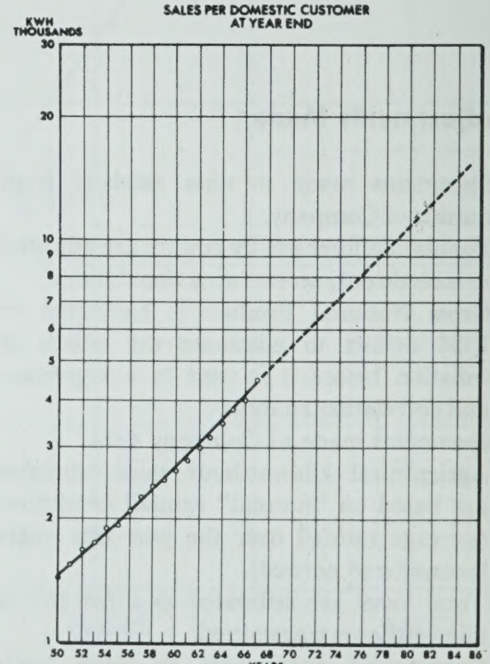


FIGURE 17

DOMESTIC SALES

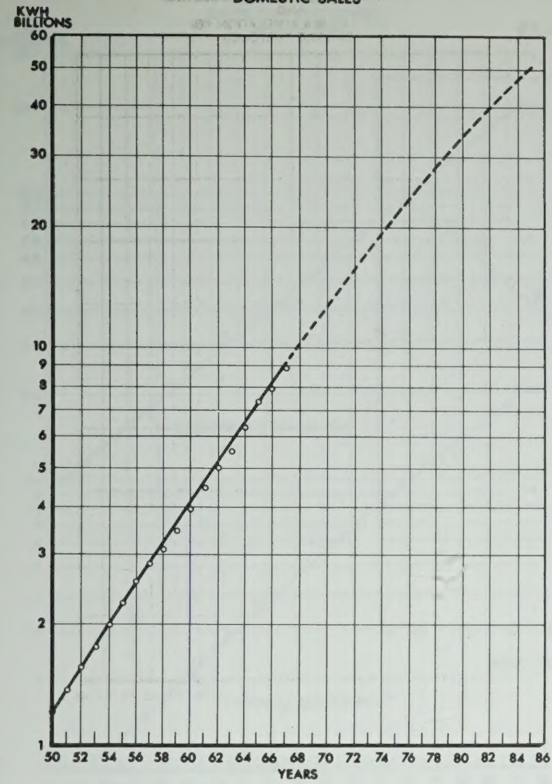


FIGURE 18

COMMERCIAL CUSTOMERS AT YEAR END AND RATIO TO DOMESTIC CUSTOMERS

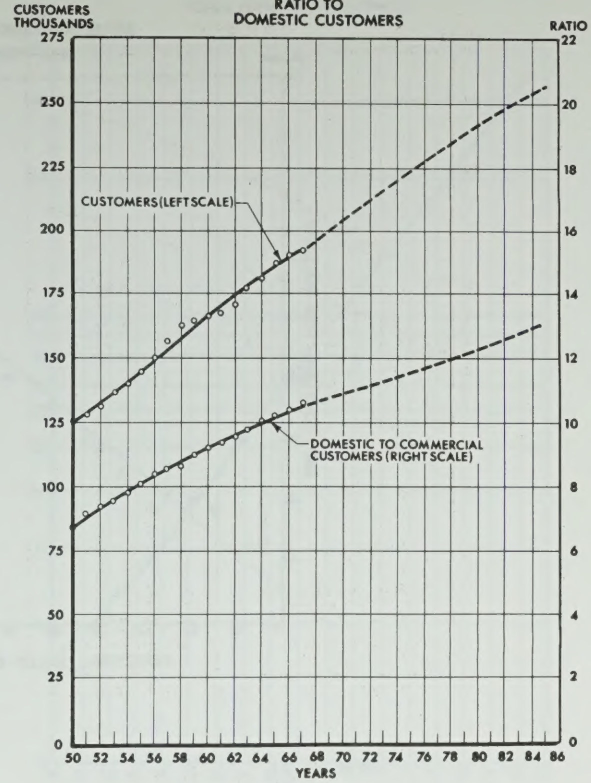


FIGURE 19

SALES PER COMMERCIAL CUSTOMER AT YEAR END

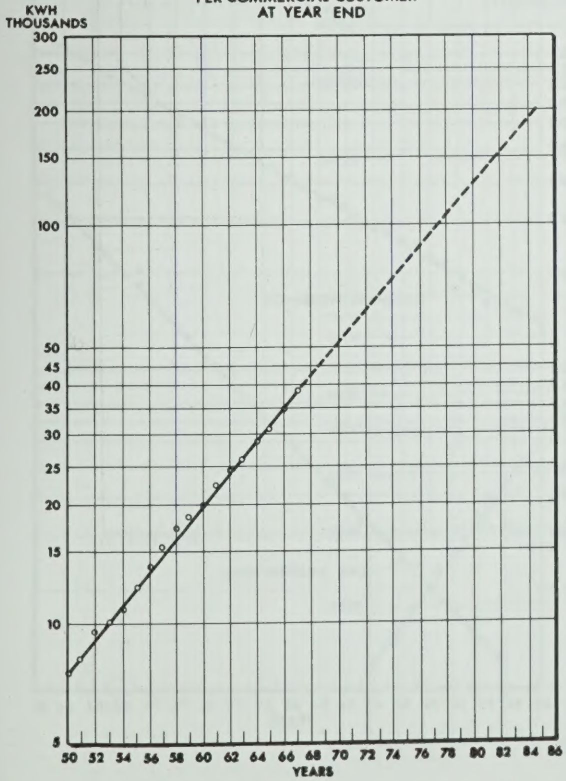


FIGURE 20

COMMERCIAL SALES

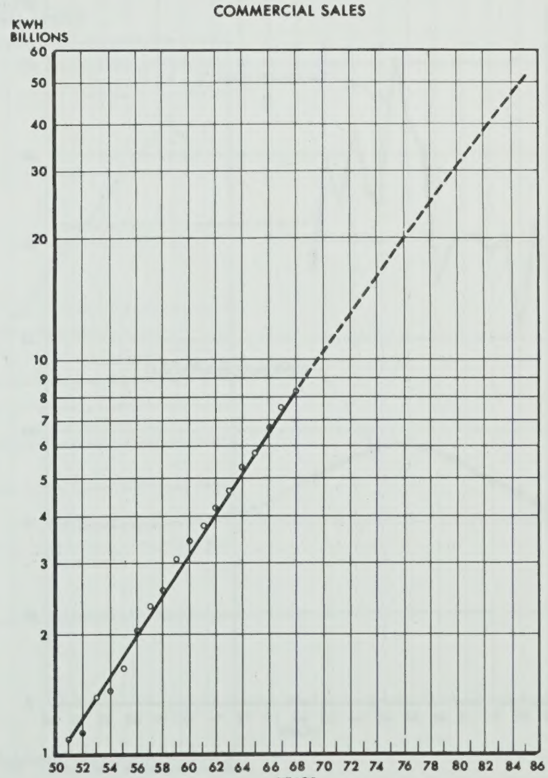


FIGURE 21
GROSS NATIONAL PRODUCT
VS.
INDUSTRIAL KWH SALES
1953-1969

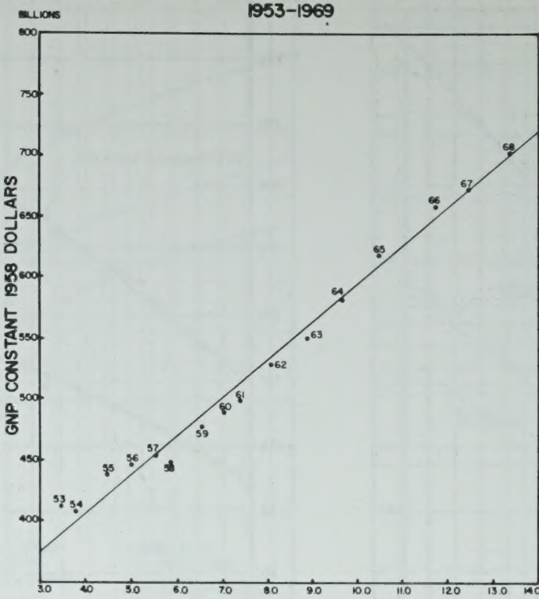


FIGURE 22

AGRICULTURAL SALES
AND CUSTOMERS
AT YEAR END

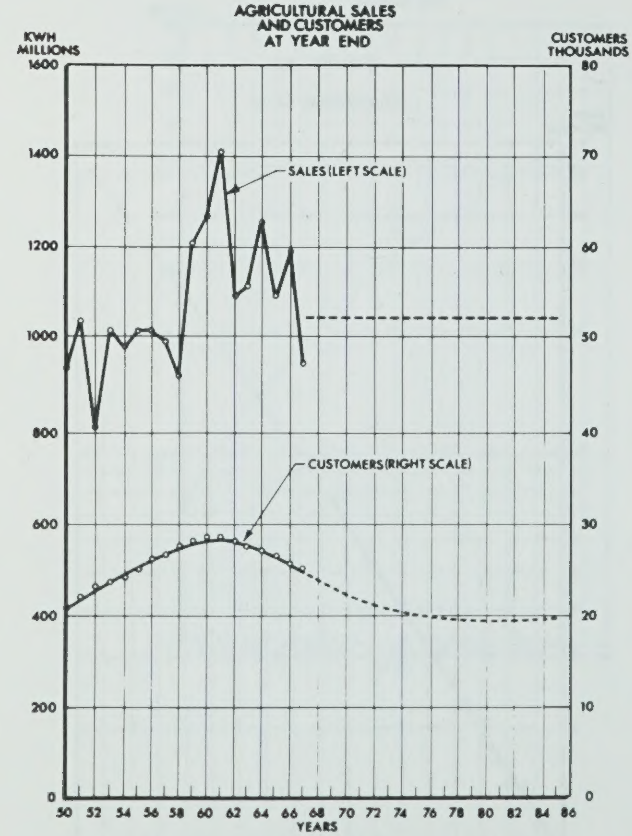


FIGURE 23

OTHER PUBLIC AUTHORITY
SALES AND CUSTOMERS
AT YEAR END

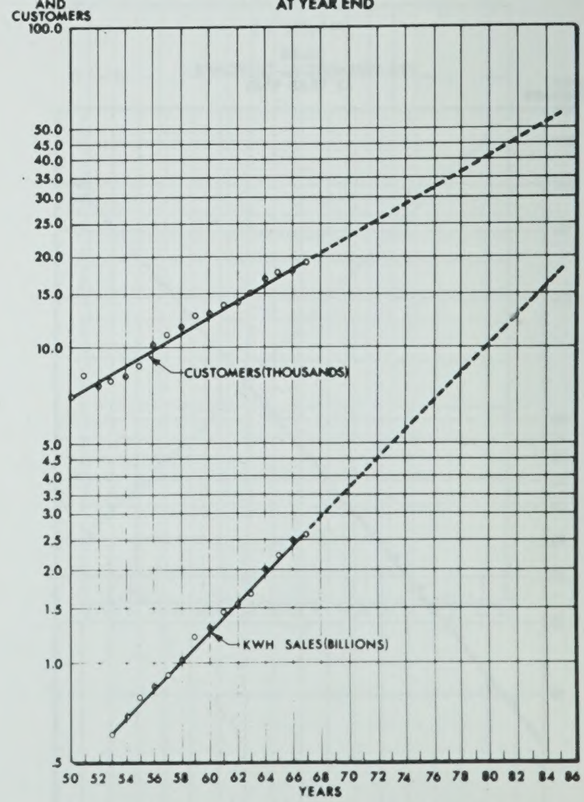


FIGURE 24

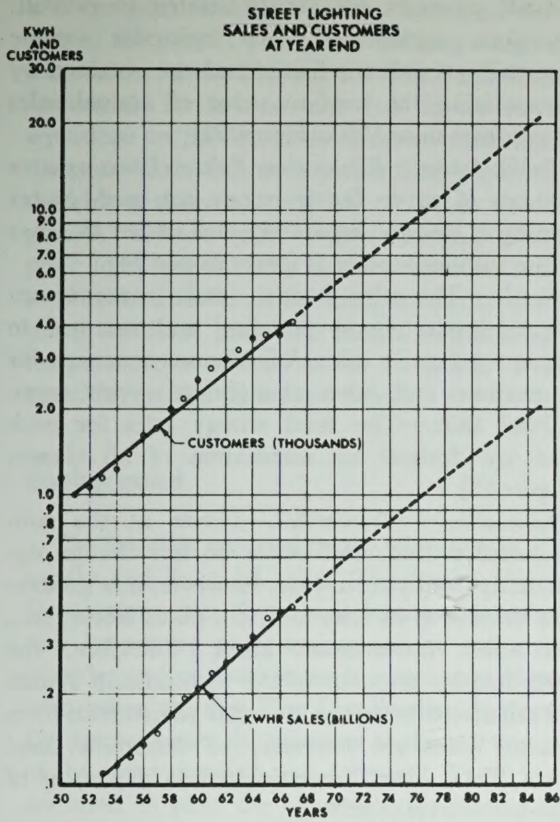


FIGURE 25

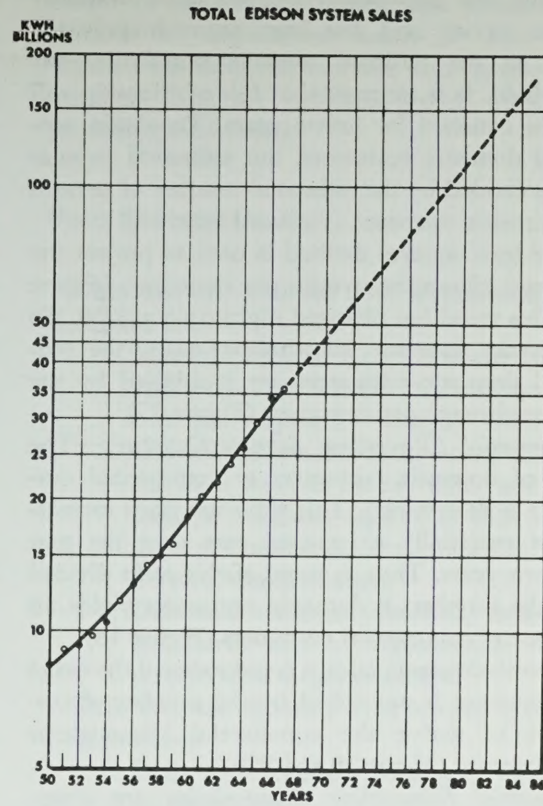
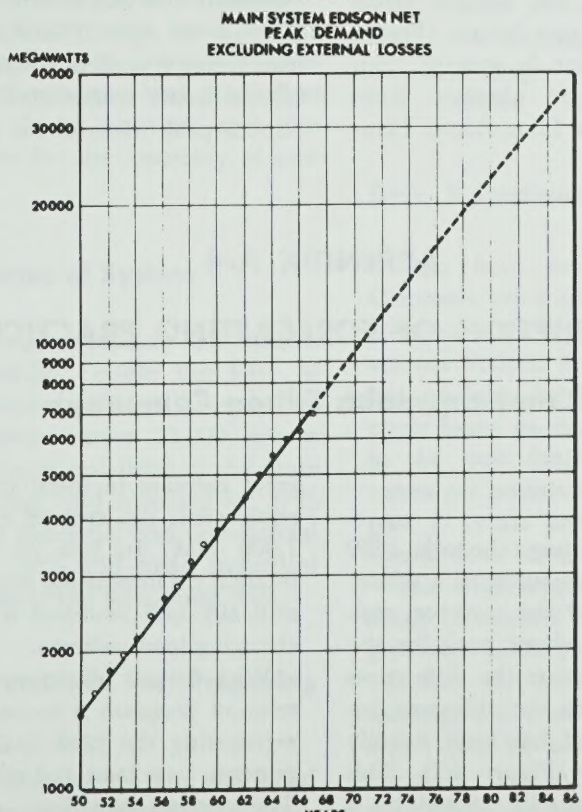


FIGURE 26



Domestic Kilowatthour Sales and Customers.—Historically the population per domestic customer in the service area has been approximately the same as the national average population per household. It is assumed that this relationship will remain constant for future years. To obtain estimated domestic customers, the estimated population is divided by the estimated number of persons per domestic customer. (Figures 14 and 15)

The least squares method is used to project the domestic kilowatthour sales per customer. (Figure 16) This trend has changed slightly since 1958. To obtain the domestic kilowatthour sales, the estimated domestic customers are multiplied by the estimated usage per customer. (Figure 17)

Commercial Kilowatthour Sales to Customers.—The ratio of domestic customers to commercial customers is determined. This ratio has been increasing at essentially a constant rate over the past eighteen years. Thus, a trend of this ratio divided into the number of domestic customers yields an estimate of commercial customers (Figure 18)

As with domestic sales, a trend value of the usage per customer is multiplied by the number of customers to derive the commercial kilowatthour sales forecast. (Figure 19 and 20)

Industrial Kilowatthour Sales.—Sales are determined by extrapolating a correlation between the annual industrial sales and the annual Gross National Product in 1958 constant dollars. (Figure 21) The correlation coefficient is greater than 0.99. Predictions of GNP are obtained from Stanford Research Institutes's Long-Range Planning Service.

Agricultural Kilowatthour Sales.—Sales for agricultural purposes are closely related to rainfall. Therefore, agricultural sales estimates assume "normal" rainfall conditions and are obtained by extrapolating the median value of annual sales for the years since 1950. (Figure 22)

Public Authority Kilowatthour Sales.—Least squares methods of curve fitting trends are used. Street lighting is trended separately and added to other public authority totals. (Figures 23 and 24)

Resale.—The sales to each resale customer are forecast separately by trending and summed to obtain total resale sales. Adjustments are made for annexations and other changes in service areas.

Total Sales.—The total energy sales for each year are derived by summation of all classes. (Figure 25)

Kilowatthours Transmitted.—Losses at the subtransmission level and below do not change significantly from year to year. However, new generation because of its size, location, plant factor, etc., can affect transmission losses. Therefore, the losses for this segment of the transmission system are calculated to determine what adjustments from present losses are necessary to determine total losses. Total losses are estimated as a percent of kilowatthours transmitted.

Peak Demand.—The annual load factor for the Company has not shown any trend movement in the past ten years. Therefore, the ten-year average load factor is used in conjunction with the forecast kilowatthours transmitted to derive the forecast annual peak demand for the system. (Figure 26)

APPENDIX A-4

DESCRIPTION OF FORECASTING PRACTICE

(Commonwealth Edison Company)

Summary

From the turn of the century through 1959 Commonwealth Edison had always been a winter peak load Company. In 1960 the summer peak load exceeded the following winter peak for the first time. For the next few years the differences were minimal until 1964 when the difference increased to over 400 MW and has been steadily increasing every since. (See Figure 27). This sudden change in 1964, primarily caused by a great increase in installations of air conditioning equipment, also created daily load swings of over 1,000 MW. In face of these conditions it was thought the forecasting method should be examined critically and modified if necessary to reflect the changing load patterns.

With the use of computers and a statistical correlation program a technique was developed for segregating the peak load into two major components, base load and temperature sensitive load. The derived equations, or models, are used as

the basic peak load forecasting tool. Values for average peak making weather, based on the history of the past 21 years, and the long range trend line values of the Federal Reserve Bank Index of Industrial Production are the input to these equations to produce new summer peak load estimates. Variations in weather and expected industrial activity as well as variations in future growth rates are tested to give a range of probable peak load values. This same procedure is being used to forecast loads for each month of the year using the same base load model but altering the temperature sensitive model to utilize weather variables applicable to each month.

Background

The forecasts are used by the engineering, power supply and financial areas. The System Planning Department uses these load forecasts to schedule new generating units and associated transmission facilities and to provide for the exchange of power with other utilities. The Distribution Engineering Department uses the forecasts as the starting point of the more detailed area forecasts. These in turn are used to plan the capability for serving more customers and larger loads. Planned maintenance and overhauling of generating units is scheduled by the Power Supply Department based on the future year's peak load forecast. Using load forecasts to project kilowatthours generated, the Budget Department estimates future revenues and also makes long-range plans for the financing of new plant expenditures.

General Characteristics of System

The Company has approximately 2.5 million customers with 1.2 million inside the City of Chicago and the remainder outside Chicago. The entire service area covers about 13,000 square miles covering the northern one-third of the State of Illinois. The residential load accounts for 35% of the total while large industrial and commercial customers account for 29% and small industrial and commercial customers the remaining 36%.

Organizations Reponsibile for Preparing Forecasts

The Load Analysis Department and the Load Estimate Sub-Committee are responsible for making load forecasts. The members on the Committee consist of the financial, sales, and administrative officers, the department heads of those major departments using the forecast, and representative members from the technical groups involved in producing the forecast.

Data Sources Used

Data that are obtained from sources outside the Company are:

1. Monthly Federal Reserve Board Index of Industrial Production.—Seasonal and Non-Seasonal Adjusted.—Monthly Bulletin.
2. U.S. official weather data.—daily data from the local weather bureau office and yearly data on magnetic tape from U.S. Department of Commerce, Environmental Science Service Administration.
3. Industrial vacation schedules, strikes, and shutdowns due to maintenance work.—directly from large customers.

Data that are obtained from sources within the Company are:

1. Daily light intensity readings.—Load Dispatcher's Office
2. Daily peak loads and time of peak and daily kilowatthours generated.—Revenue Accounting Department
3. Voltage reductions.—Load Dispatcher's Office

Data Adjustments Made

Data from sources outside and within the Company are stored on magnetic tape to form a historical data file dating back to 1948. Since the current Federal Reserve Board Index figures are not available for several months, projections are made based on the current and expected activity in the near future. For the longer term FRB values are projected based on the trend line of the past 21 years and modified to reflect different assumptions on the long-term economic outlook.

The actual weather data are used to derive other forms of weather information such as cooling degree days, heating degree days, THI, average wind velocities and wind direction. The light intensity readings are used to calculate a 24-hour value and values for one-hour and two-hours prior to the peak load. All the calculated information is stored on tape and consists of over 70 weather

FIGURE 27

COMMONWEALTH EDISON CO.

ACTUAL SUMMER & WINTER PEAK LOADS

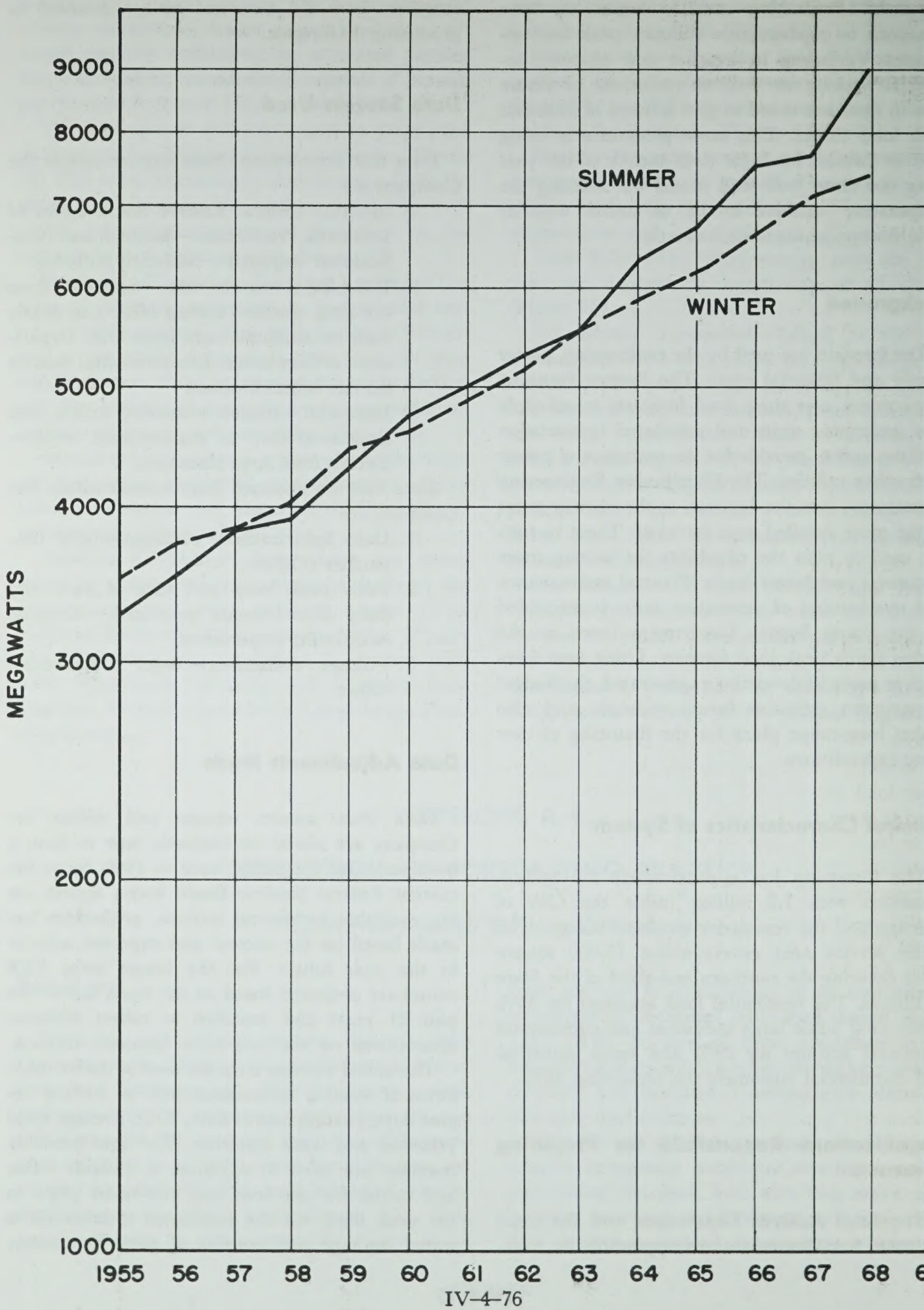


TABLE 28

Summer Peak Loads—Comparison of Actual Load with Computed Values Using Model

[Load in MW]

Summer of year	Time and date of occurrence	Peak load (actual)	Computed loads using model			
			Base load (1955–68 trend line)	Temperature sensitive load (1959–68) formula	Peak load	Difference in computed over actual load
1955	Aug. 29, 1–2 p.m.	3251	2736	506	3242	– 9
1956	June 13, 1–2 p.m.	3512	2960	544	3504	– 8
1957	Aug. 15, 1–2 p.m.	3812	3161	619	3780	– 32
1958	Aug. 11, 1–2 p.m.	3901	3237	611	3848	– 53
1959	Aug. 25, 1–2 p.m.	4299	3288	1009	4297	– 2
1960	Sept. 8, 1–2 p.m.	4726	3630	1099	4729	3
1961	Aug. 31, 1–2 p.m.	4970	3831	1029	4860	–110
1962	Aug. 24, 2–3 p.m.	5281	4055	1246	5301	20
1963	July 1, 1–2 p.m.	5527	4118	1475	5693	166
1964	Aug. 3, 1–2 p.m.	6291	4462	1930	6392	101
1965	July 23, 1–2 p.m.	6671	4746	1894	6640	– 31
1966	July 12, 1–2 p.m.	7491	5105	2368	7473	– 18
1967	June 15, 2–3 p.m.	7643	5517	2172	7689	46
1968	Aug. 23, 1–2 p.m.	8950	5770	3229	8999	49

variables as well as the basic weather data on hourly temperatures, humidity, wind, etc. (See Figures 31 and 32.)

Analytical Steps Prior to Forecasting

Base load is defined as that portion of peak load which is not directly related to summer weather variations. To develop the base load equation those weekdays which have very little, if any, weather load are selected. It has appeared that days with three or less cooling degree days and seven or less heating degree days seem to fit that requirement. However, preliminary weather computer runs using these variables indicate that more than just a year-to-year growth appears to be affecting the base load. The log of the daily peak demand for those days is again correlated, along with the basic time variable, with the Federal Reserve Board Index of Industrial Production Non-Seasonally Adjusted and the two weather variables, cooling and heating degree days. These four variables appear to explain almost all of the variations and improve the correlation to a coefficient of correlation of over 0.99. Using this equation a daily base load is calculated for all days and inserted in the historical file.

Even with this high degree of mathematical consistency, the original daily peak loads used to derive the base load formula differs from the derived values in a manner that does not always appear to be random. A study of the data indicates that in some years most of the deviations are negative and in other years most are positive. It is believed these variations reflect the cyclical impacts not completely explained by the variation in FRB index. In order to obtain a base load which more nearly follows the actual load growth pattern, all the deviations in each year are averaged and used as an annual adjustment. This adjustment together with the calculated effect of industrial customer vacations, strikes, load control measures and other local conditions affecting load are all inserted in the historical file as adjustments to be made to the calculated base load to obtain the adjusted base load.

Heat sensitive load is defined as the remainder of peak load after subtracting the adjusted base load from the total. The major problem in developing a heat sensitive model is the selection of weather variables which, with a minimum of deviation, account for the load under a given set of weather conditions. Days having 16 or more cooling degree days for the months of June through September are used in the analysis. The log of the heat sensitive load is correlated and tested with various combinations of 24 different variables. The following variables seem to re-occur consistently

FIGURE 29

COMPARISON OF ACTUAL SUMMER PEAK LOADS WITH COMPUTED VALUES USING MODEL

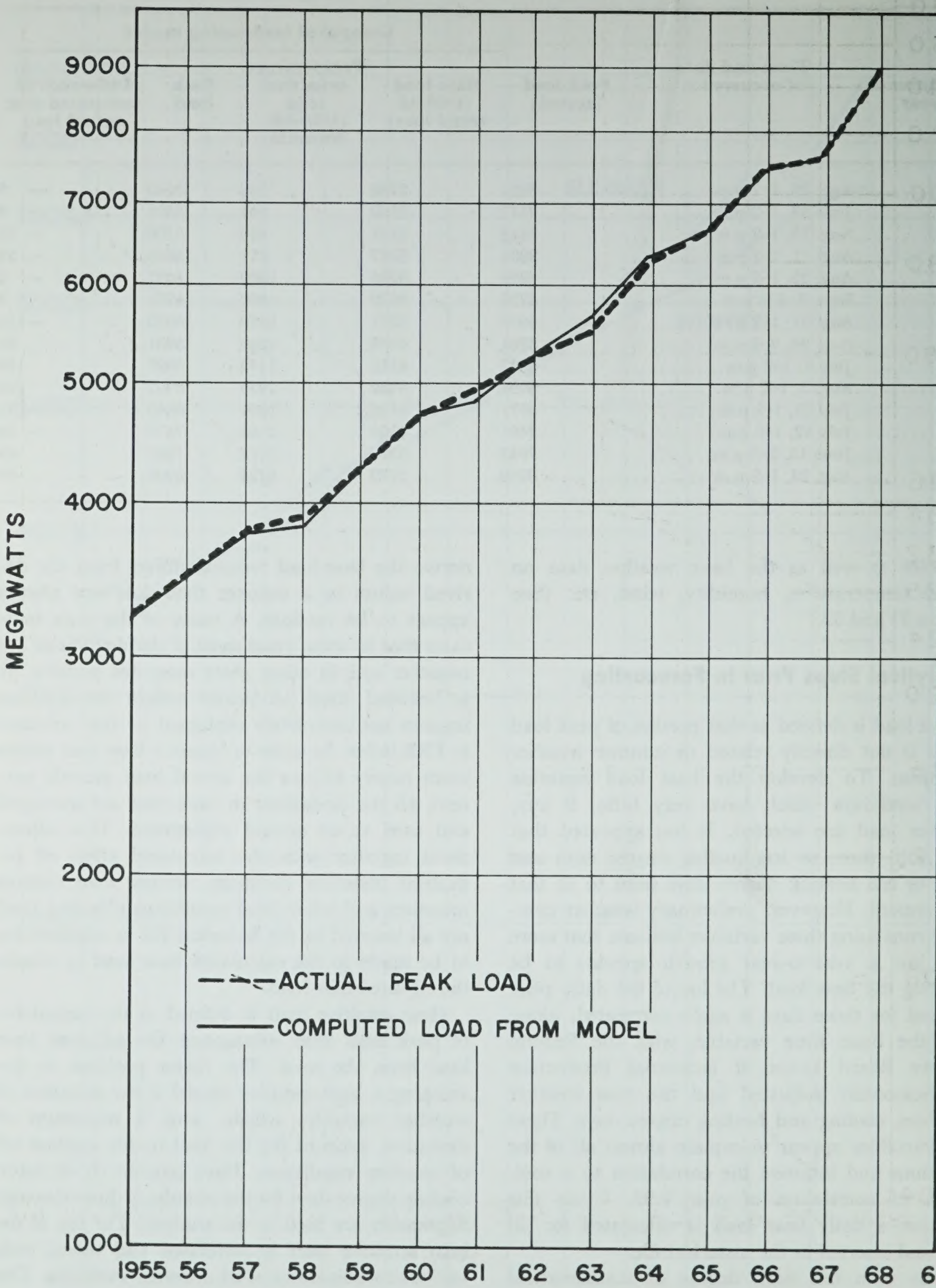


FIGURE 30

SUMMER PEAK LOADS, ACTUAL AND FORECASTED ALLOCATED BETWEEN BASE LOAD AND WEATHER SENSITIVE LOAD

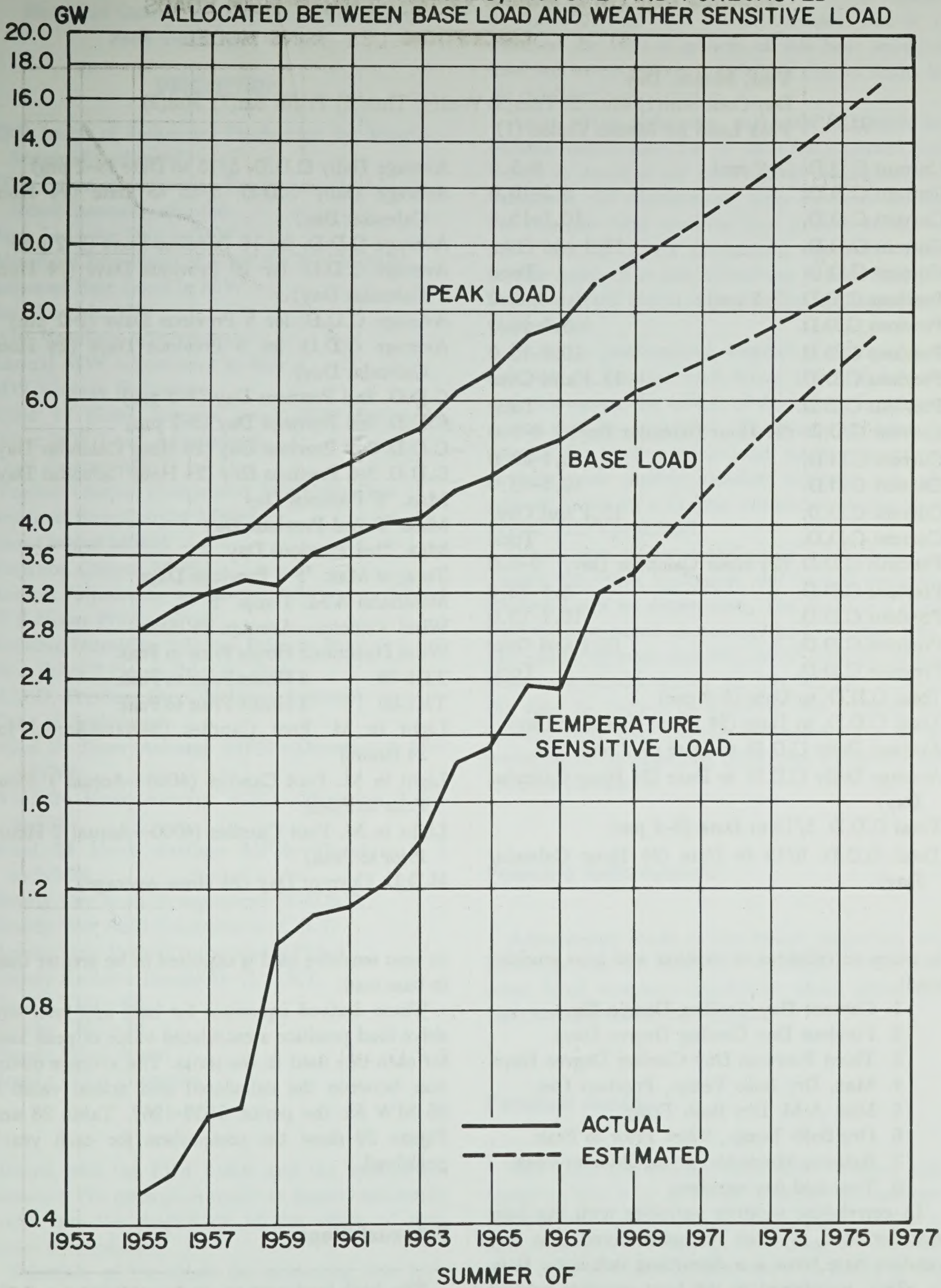


TABLE 31

Historical Data File of Weather Variables, Peak Load, and Output

DESCRIPTION

Year, Month, Day
Day Code Sun(1) Mon(2) Tues(3) Wed(4) Thur(5) Fri(6) Sat(7) Hol(9)
Peak Load for Month Coded (1)

Current C.D.D. (3–2 pm)	0–5.0
Current C.D.D.	5.1–10.0
Current C.D.D.	10.1–15.0
Current C.D.D.	15.1 and Over
Current C.D.D.	Total
Previous C.D.D. (3–2 pm)	0–5.0
Previous C.D.D.	5.1–10.0
Previous C.D.D.	10.1–15.0
Previous C.D.D.	15.1 and Over
Previous C.D.D.	Total
Current C.D.D. (24 Hour Calendar Day)	0–5.0
Current C.D.D.	5.1–10.0
Current C.D.D.	10.1–15.0
Current C.D.D.	15.1 and Over
Current C.D.D.	Total
Previous C.D.D. (24 Hour Calendar Day)	0–5.0
Previous C.D.D.	5.1–10.0
Previous C.D.D.	10.1–15.0
Previous C.D.D.	15.1 and Over
Previous C.D.D.	Total
Total C.D.D. to Date (3–2 pm)	
Total C.D.D. to Date (24 Hour Calendar Day)	
Average Daily C.D.D. to Date (3–2 pm)	
Average Daily C.D.D. to Date (24 Hour Calendar Day)	
Total C.D.D. 5/15 to Date (3–2 pm)	
Total C.D.D. 5/15 to Date (24 Hour Calendar Day)	

Average Daily C.D.D. 5/15 to Date (3–2 pm)
Average Daily C.D.D. 5/15 to Date (24 Hour Calendar Day)
Average C.D.D. for 10 Previous Days (3–2 pm)
Average C.D.D. for 10 Previous Days (24 Hour Calendar Day)
Average C.D.D. for 5 Previous Days (3–2 pm)
Average C.D.D. for 5 Previous Days (24 Hour Calendar Day)
C.D.D. 2nd Previous Day (3–2 pm)
C.D.D. 3rd Previous Day (3–2 pm)
C.D.D. 2nd Previous Day (24 Hour Calendar Day)
C.D.D. 3rd Previous Day (24 Hour Calendar Day)
Max. °F Previous Day
Max. °F 2nd Previous Day
Max. °3rd Previous Day
Total of Max. °F 3 Previous Days
Minimum A.M. Temp. °F
Wind Velocity—Average 24 Hour
Wind Direction2 Hours Prior to Peak
THI-70 2 Hours Prior to Peak
THI-60 2 Hours Prior to Peak
Light in M. Foot Candles (54200—Actual for 24 Hours)
Light in M. Foot Candles (4000—Actual 1 Hour Prior to Peak)
Light in M. Foot Candles (4000—Actual 2 Hours Prior to Peak)
H.D.D. Current Day (24 Hour Average)

in many correlations of weather and heat sensitive load:

1. Current Day Cooling Degree Days.
2. Previous Day Cooling Degree Days.
3. Third Previous Day Cooling Degree Days.
4. Max. Dry Bulb Temp., Previous Day.
5. Min. A.M. Dry Bulb Temp.
6. Dry Bulb Temp., 2 hrs. Prior to Peak.
7. Relative Humidity, 2 hrs. Prior to Peak.
8. Year and day numbers.

In correlating weather variables with the heat sensitive load, it must be remembered that any random base error is a disturbing influence. It is, in effect, transferred to the heat sensitive portion of the peak. Therefore, the unexplained variation in heat sensitive load is expected to be greater than in base load.

These derived equations for base and heat sensitive load produce a calculated value of peak load for each day used in the series. The average deviation between the calculated and actual value is 46 MW for the period 1959–1967. Table 28 and Figure 29 show the comparison for each year's peak load.

Forecast Steps

The base load appears to be growing regularly except for economic cycles which have been ex-

TABLE 32

Historical Data File of Weather Variables, Peak Load, and Output

DESCRIPTION
FRB Index of Industrial Production for Month—Seasonally adjusted
FRB Index of Industrial Production for Month—Non-Seasonally adjusted
Peak Load for Day in MW
Weather Component of Load for Day in MW
Adjusted Base Load in MW
Base Load in MW
MW Vacation Adjustment
Annual MW Adjustment to Base
MW Voltage Reduction
Rider 17 (Steel Furnace Load) MW Reduction
Other MW Load Adjustments
Total Output MWH for Day
Weather Output Component MWH for Day
Adjusted Base Output MWH
Base Output MWH
Vacation Output MWH
Annual Adjustment to Base and Strikes in MWH
°F 2 Hours Prior to Peak
Relative Humidity 2 Hours Prior to Peak
Dew Point 2 Hours Prior to Peak
H.D.D. Previous Day (24 Hour Average)
Time of Peak Load
Wind 24 Hour Average MPH—Direction 1 NW to NNE
Wind 24 Hour Average MPH—Direction 2 NE to SSE
Wind 24 Hour Average MPH—Direction 3 S to WNW
Hourly Dry Bulb Temperature °F C.S.T.
Hourly Wet Bulb Temperature C.S.T.
Hourly Dew Point Temperatures C.S.T.
Hourly Relative Humidity % C.S.T.
Hourly THI—60
Hourly THI—70
Hourly Wind Speed
Hourly Wind Direction

plained with the FRB Index and the annual adjustment. No attempt is made to project economic cycles but the magnitude of the effect of such cycles is calculated.

Selection of the basis for projecting the heat sensitive load is the most important determinant of the future load forecast. It is first assumed the weather relation expressed in the model will remain constant through the period forecast. But it is assumed the rate of growth of this heat sensitive load will not continue indefinitely due to limits in air conditioning saturation.

As an aid to judgment, past rates of growth for periods shorter than the 10 years are analyzed and trends in levels of air conditioning saturation are examined. Of considerable help in these studies are the past heat sensitive load growth trends of other electric power companies, especially those further south. The rate of increase in heat sensitive load predicted tapers somewhat in the immediate years ahead.

So far as peak-making weather is concerned, it can only be assumed each future year will be normal. However, the effects of deviations from normalcy can be evaluated. To determine what is normal for present peak load making purposes, average peak making weather variables are calculated based on a 21 year occurrence at the time of each year's peak load.

When each factor contributing to random deviation has been evaluated, the overall probable deviation can be determined. The result is a peak load forecast based on average peak making weather occurring such that 50% of the time the actual peak load should exceed the forecast and 50% of the time be below. In addition, the possible deviations from this forecast are stated as a set of probabilities or gambling odds. (See Figure 30 for Chart of Forecast.)

Forecast Adjustments

Adjustments made to the initial projection are generally due to industrial vacations, strike and other local economic conditions which affect the base load portion of the forecast.

Forecast Audits

The Load Forecasting Committee reviews and approves the load forecasts. During the summer months the Load Analysis Department makes a daily check of the two models, using the current daily data in its calculation and comparing to the daily peak load.

Appendix A-5[1]

Demand Forecasting on a Probabilistic Basis for the Electric Utility Industry (PEREC)

I. Introduction

The long-range forecasting project described briefly herein is part of a research activity of the Purdue Energy Research & Education Center (PEREC), an endeavor of Purdue University, supported by a group of midwestern electric utilities. The initial research objectives in 1966 were limited to reviewing forecasts, data, and techniques currently in use by the industry. More tangible objectives were quickly developed and efforts have since been concentrated on weekly forecasting for a five-to-seven year period.

Although it has been a general practice in the industry to forecast only annual or possibly seasonal peak demands, it was felt that a computer program should be developed to forecast weekly peak demands on a probabilistic basis. That is, the forecast should involve the standard deviation or variance as well as the expected or mean values themselves of weekly peak demands. This research project was intended to produce techniques for forecasting over a seven year period with a validity consistently greater than those obtained by current procedures, even though it was recognized that the accuracy of any forecasting procedure tends to deteriorate with lead time.

The PEREC forecasting program is actually a collection of programs assembled into a rather complex program package. The program package is convenient when using a medium to large computing center but would exceed the capabilities of smaller computing systems. However, many of the subroutines have stand-alone capability and could be run on smaller computers with the forecast being produced in a semi-automated fashion by means of a series of computer runs coupled by some manual manipulation of data.

Normally the program should not be expected to produce accurate forecasts on the first attempt with a particular company's data. This limitation is partly unavoidable and not really a weakness in the program since each utility company supplies a system which is unique in its load pattern and growth. Hence, the forecast program must be adapted to the characteristics of a particular company's load.

Energy KWH sales forecasting was not given thorough consideration during the early phases of the project because it was felt that serious development of a direct peak demand forecasting was necessary before comparing demand and energy methods. It is quite possible that future exploration would include work on a KWH energy approach.

II. Basic Requirements

Three basic requirements have dominated the development of the forecasting methodology described herein:

(a) The load forecast at a specified future time must be represented as a random variable with properties determined by its probability distribution function. Assuming a normal distribution, the mean value and the variance or standard deviation of the forecast are the two parameters which define the distribution.

(b) Although it is general practice in the industry to forecast annual or seasonal peak demands and then to convert these forecasts into monthly peaks by multiplying by appropriate ratios, the approach adopted here proceeds by first determining weekly peak demands. The reasons for this approach are first, the growing complexity of planning increases the need for accurate weekly demand forecasts; second, the availability of digital computers facilitates the extra data processing and third, annual, seasonal or monthly demands can be computed from weekly demands in a systematic manner.

(c) The choice of techniques is influenced by the desire to have a forecasting procedure readily adaptable to the needs of many different companies. This objective makes it necessary to anticipate the di-

[1] Prepared by Professor K. Neil Stanton—Purdue University.

verse ways that load growth can occur in companies which are spread across the country geographically and subjected to varied growth and weather conditions. Essentially this amounts to developing a general forecasting methodology rather than concentrating on the needs of a particular company.

III. General Description of Forecasting Methodology

Growth of the base load is extrapolated by a time polynomial which is determined by exponentially-weighted regression, with the more recent data being assigned progressively higher weights in an exponential manner. Since experience has demonstrated that it is important to remove seasonal effects from the data before attempting to fit the time polynomial, the first step in the program is separation of the weekly peak demand into a weather sensitive component and a non-weather sensitive (base load) component by using weather-load models determined from daily data. When the base load component of weekly peak demand is trended by the exponentially weighted regression program, no difficulty is encountered in fitting as the trend a second-order time polynomial. Higher-ordered polynomials have been tested but are not necessary for this application.

Since the dominant factor in the seasonal component of electricity peak demand is the weather sensitive component (heating and/or cooling load) useful weather-load models are obtained by correlating demand with an appropriate weather variable. In making a forecast, observation of the evolution of weather-load models from historical data is necessary. The resulting information is used to project the model forward to the desired time of forecast. Since detailed weather forecasts are not available on a long-range basis, weather statistics rather than weather forecasts are used with the model to calculate corresponding statistics for the weather-induced demand. The steps in determining the growth of the weather-load model can be summarized as follows:

(a) Choose a suitable weather variable and fix the structure of the model.
(b) Use historical load and weather data to compute the coefficients of the model season-by-season, winter and summer.
(c) Project the coefficients of the model forward in time.

IV. Details of the Forecasting Methodology

The overall forecasting methodology is shown in the block diagram, Figure 33. Two basic sets of demand and weather data must be prepared, one on a daily and the other on a weekly basis. The first set of data is used for weather-load modeling and the second in the forecasting program.

A. Weather-Load Modeling Program

1. *Classification, ordering and plotting of data*

Inputs to the weather-load modeling program are recorded daily peak demands, associated coincident dry bulb temperature, and T_1 and T_2. (See 2 below for a description of T_1 and T_2.) Peak demands and associated temperature data are separated annually into two classes: Mondays in one class and Tuesdays through Fridays in the other.

Different electric utility systems may have other classification patterns, but weekend peaks are usually low and need not be considered because they do not ordinarily contribute to weekly peak demand. Scatter diagrams for each class are plotted, with the points on the diagram representing paired daily peak demand—coincident dry bulb temperature, as recorded. For the purpose of illustration the weather-load model of the form shown in Figure 34 is fitted to the scatter diagram of the Tuesday through Friday class of data. For each class, there are as many scatter diagrams and weather-load models as there are years of recorded data.

2. *Peak demand significant temperatures*

The temperatures T_1 and T_2 are fixed and do not change from year to year. T_1 is the heating significant dry bulb temperature and T_2 is the cooling significant dry bulb temperature. Temperatures between T_1 and T_2 are assumed to have a zero impact on peak demand.

3. *Mathematical derivation of the weather-load model*

Since T_1 and T_2 are fixed, the model for each year of recorded data is fully determined by three parameters, D_0, K_w, and K_s, which are defined as follows: D_0 is the nonweather sensitive component of peak demand associated with temperatures between T_1 and T_2; K_w is the winter weather coefficient and measures the megawatts of heating load per degree of temperature below T_1; K_s is the summer weather coefficient and measures the megawatts of cooling load per degree of temperature above T_2. Although it is possible to measure

D_0 automatically, this parameter is initially determined graphically by inspection of the scatter diagram. K_w and K_s are determined by fitting the following equations (these will be recognized as point-slope forms of straight lines) to the winter and summer weekly data, respectively:

$$D_{wp} - D_0 = K_w \cdot (T - T_1)$$

$$D_{sp} - D_0 = K_s \cdot (T - T_2)$$

where:

D_{wp} = daily winter peak demand for temperature below T_1

D_{sp} = daily summer peak demand for temperature above T_2

T = daily recorded coincident dry bulb temperature associated with either D_{wp} or D_{sp} as the case may be

D_0, K_w, K_s, T_1 and T_2 have all been defined previously.

For each year of recorded data for temperatures below T_1, the axis zero point is translated to T_1 and D_0 while for temperatures above T_2 the axis zero point is translated to T_2 and D_0. Then, by the standard linear regression technique, a straight line is fitted to the two sets of data distinguished by temperatures below T_1 and above T_2. It is evident that K_w, the winter weather coefficient, is always negative and is the slope of the winter daily peak demand—coincident dry bulb temperature linear regression line. Similarly K_s, the summer weather coefficient, is always positive and is the slope of the summer daily peak demand—coincident dry bulb temperature linear regression line. For each year K_w and K_s are updated and their values supplied as inputs to the forecasting program. In all computations involving K_w, its sign is assumed to be positive rather than negative, since only its magnitude is of interest. For each year of recorded data, therefore, separate values of D_0, K_w and K_s are computed, although only the values of K_w and K_s will be further processed.

B. Forecasting Program

Inputs to the forecasting program are recorded weekly peak demands, associated coincident dry bulb temperatures, annual values of K_w and K_s computed in (A.3) above, and manually projected values of K_w and K_s computed in (2.a) below.

1. *Forecasting non-weather sensitive weekly peak demand (the base load)*

a. For each year of recorded data the weather-load models are used to eliminate the weather-sensitive component from the weekly peak demand. If the temperature corresponding to such demand is less than T_1, then $K_w \cdot (T_1 - T)$ is subtracted from the weekly peak demand in order to eliminate the heating component, with K_w designated as positive. If the temperature is between T_1 and T_2 no adjustment is made even though a marginal combined heating and cooling component may be present in peak demand. If the temperature exceeds T_2, then $K_s \cdot (T - T_2)$ is subtracted from the weekly peak demand in order to eliminate the cooling component. The residual weekly peak demands are the nonweather sensitive components.

b. The base load is approximated by using the exponentially-weighted regression program to fit a second degree time polynomial to the non-weather sensitive components of weekly peak demand. Experience has demonstrated that nothing is gained by using a higher ordered equation. Before the second degree equation can be fitted, however, it is necessary to remove the seasonal variations which generally remain after the weather sensitive components have been removed. Vacation patterns, annual industrial production cycles, grain drying, etc., provide seasonal fluctuations in load which are not directly weather induced. A modification of the Census II Seasonal Adjustment Program developed by Shiskin, adapted to weekly rather than monthly data, is used to separate the base component of peak demand into seasonal and seasonally adjusted elements.

c. The exponentially-weighted regression program is then used to fit the second degree time polynomial to the weekly seasonally adjusted components of the base demand. Assuming normality, it follows that the probability distributions for weekly base demands are fully specified by their mean and variance. The mean value of the base demand is forecast by extrapolating the trend line. The residual errors in fitting the trend line and the variances of the coefficients of the trend equation are used to compute the variance of future weekly base demands.

2. *Forecasting weather sensitive weekly peak demand*

a. For each year in the forecast interval K_w and K_s are projected. This is one of the few steps that must be performed manually. There are two reasons for this. First, only one value of K_w and K_s per year of recorded data is available and extrapolation using the computer is impractical unless the growth is very orderly. Second, the judgment of marketing specialists should be considered when projecting growth in K_w and K_s because these coefficients relate directly to efforts to build new electric heating and cooling loads.

b. The coefficients K_w and K_s are treated deterministically rather than probabilistically, that is, the variances of K_w and K_s are not used to forecast weather sensitive weekly peak demand. This assumption depends for its validity on the weather variable, the coincident dry bulb temperature in this particular forecasting model, contributing most of the variance in the weather-sensitive load, as opposed to the variances of K_w and K_s. In electric utility systems where more than 10% of the winter and summer weekly peak demand is weather-sensitive, this assumption appears to be valid. The necessity for providing variance estimates for predicted values of K_w and K_s, a very difficult procedure, is also avoided.

c. For each of the 52 weeks in a year, the mean and variance of the coincident dry bulb temperature are calculated from recorded data. This results in 52 means and variances per year being computed for probability distributions which, in this instance, are non-normal. These means and variances are applied to the annual projected values of K_w and K_s in a very complicated manner in order to obtain the forecast of time variant means and variances of the weather-sensitive component of weekly peak demand. For as many as seven years into the future, therefore, 52 time variant weekly means and associated variances per year are computed for the weather sensitive component of weekly peak demand.

3. *Combining the weather sensitive and non-weather sensitive forecasts of weekly peak demand into a forecast of total weekly peak demand*

Since means and variances of the weather sensitive and non-weather sensitive components of weekly peak demand for each year in the forecast interval have been individually projected, it is possible to forecast total weekly peak demand using means and variances. This is done by adding, on a corresponding week-by-week basis, the weather sensitive and non-weather sensitive means, and the weather sensitive and non-weather sensitive variances. This computational procedure is valid because the means and variances of a new probability distribution may be developed as a linear combination of the means and variances of two separate probability distributions. The end result, therefore, is a forecast of total weekly peak demand in terms of means and variances; if the weather sensitive component is small relative to the base demand, the probability distribution of total weekly peak demand is approximately normal. Technically, since the base load was assumed to be normally distributed, and the weather sensitive load is known to be non-normal, total peak demand is also non-normally distributed. Generalized probability statements can be determined rigorously only if the exact distribution of weekly peak demand is computed, and the necessary computational procedures are being developed at the present time.

V. Comments on the Methodology

The procedure of forecasting herein described uses probabilistic techniques to determine directly the weekly peak demands. The following conclusions should provide further comprehension of the methodology:

A. It is essential to separate seasonal effects from the weekly peak demand data before fitting the trend line. Of several approaches which were investigated, the separation of weather sensitive peak demand followed by the Shiskin technique for seasonal adjustment of non-weather sensitive peak demand has proved to be the most satisfactory.

B. A second-order time polynomial has provided adequate representation of the base load trend line. When seasonals are removed, the exponentially-weighted regression program performs very well. Many general purpose regression programs would be adequate, provided that they allow the variance to be calculated when extrapolating the trend line.

C. Weather-load models are most important and should be determined using week-day peak demand and weather data.

D. It is advisable to keep the weather-load models fairly simple so that calculation of variance is practical when extrapolating the growth of weather-load models. The effect of market saturation on weather sensitive load growth is quite important. Its treatment analytically is difficult and should be supplemented by customer surveys.

E. The variance of the forecast arises from three sources; the extrapolated base load trend line (increases with time), the coefficients of the weather-load model and the weather variable itself. For many companies, the latter source of variance will dominate at least for the first two or three years of the forecast and the variance

FIGURE 33
WEEKLY PEAK DEMAND FORECASTING METHODOLOGY

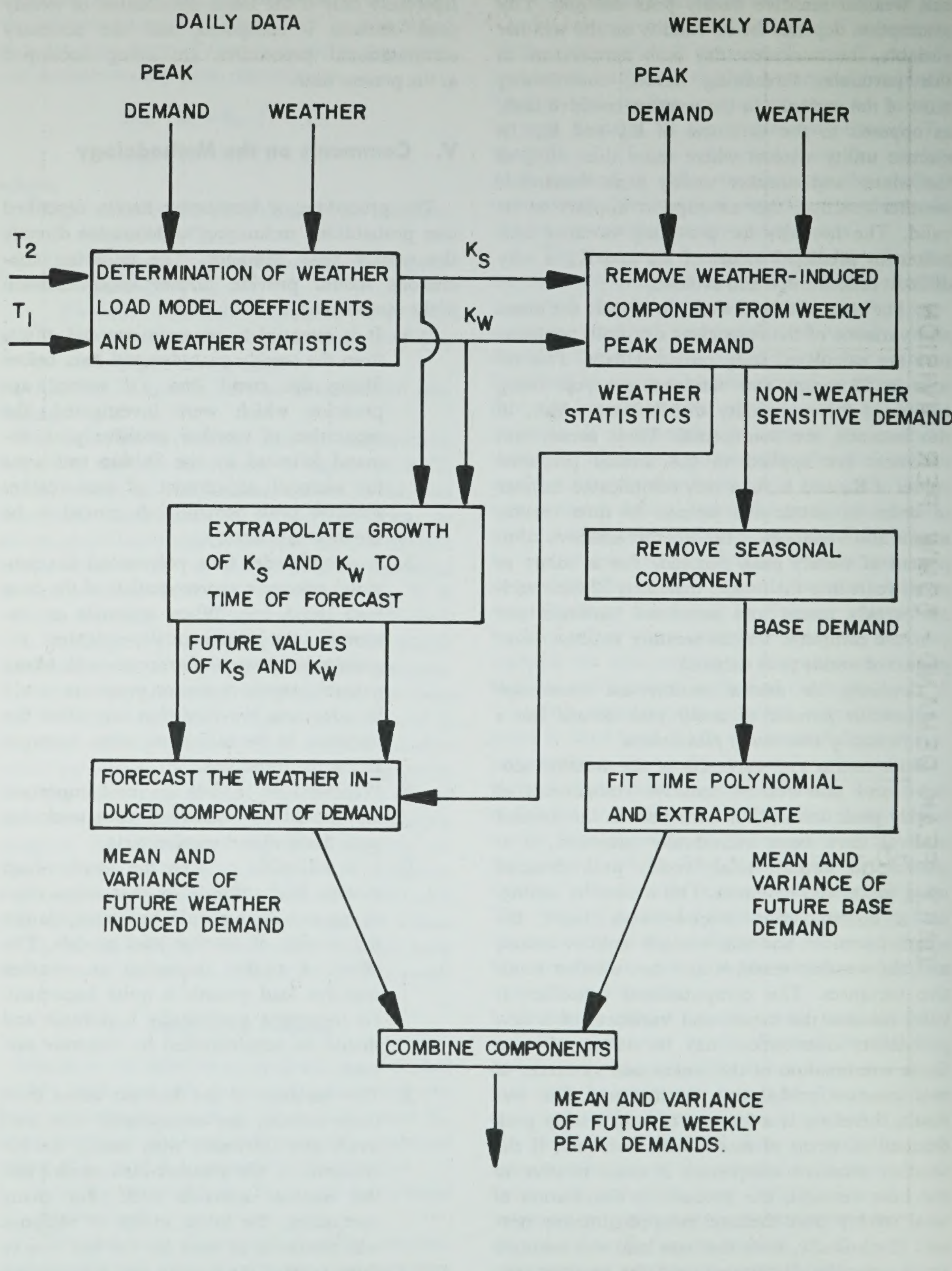
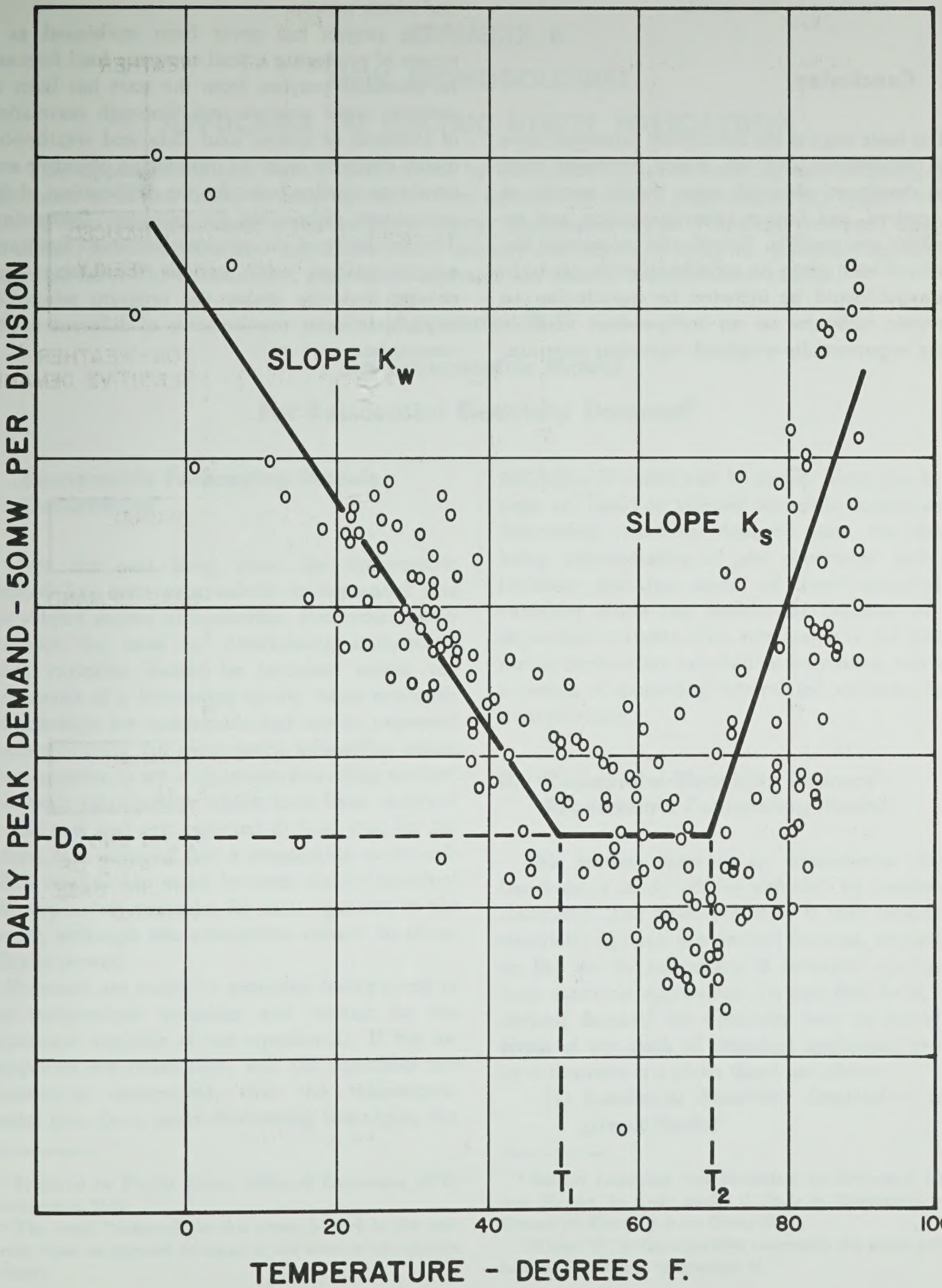


FIGURE 34

TYPICAL SCATTER DIAGRAM
FOR ONE YEAR



in the trend line will dominate in longer term forecasts (six or seven years). Hence, extreme analytical detail may frequently be avoided by ignoring the variance of weather-load model coefficients, which was done in this model.

VI. Conclusion

The basic steps of the forecasting procedure have been determined and the major programs have been developed although some details remain to be resolved and further experimentation and refinement are possible. Specifically, economic factors have been given no consideration in this technique but could be included by introducing an economic indicator as an independent variable in the exponentially-weighted regression program. Further, the accuracy of the weather-load model can probably be increased significantly if the dry bulb temperature is replaced by a more sophisticated choice of weather variable. It is not necessary to use the same weather variable for summer and winter seasons.

The project has never been envisioned as a means of producing a final company load forecast. Its intended purpose from the start has been to perform rapid analysis and thorough correlation of elements of system load data and weather-induced effects in order to produce an objective and consistent starting point for the deliberation of the committees responsible for company forecasting. The flexibility of the program structure facilitates experimentation with various forecasting procedures and also makes the program adaptable to the particular requirements of different utility companies.

APPENDIX B
NEW METHODOLOGIES
APPLICABLE TO ELECTRIC UTILITY FORECASTING

This Appendix contains three papers written by Committee members outlining new methodologies applicable to electric utility forecasting studies. The methodologies have been successfully applied in the field of macroeconomic analysis and studies of energy consumption in the American economy. Chapter VI of the report describes how the electric utility industry can benefit by using the systematic approaches described here. The opinions and conclusions expressed are those of the individual authors.

Appendix B-1[1]
An Econometric Model
For Residential Electricity Demand[2]

I. Econometric Forecasting Models Generalized

Over the past forty years the econometric method has been progressively incorporated into the subject matter of economics. Economic theory provides the basis for determining analytically what variables should be included within the framework of a forecasting model. Most economic relationships are measurable and can be expressed mathematically. An econometric forecasting model is an equation or set of equations describing selected economic relationships which have been observed in the past and are expected to hold true for the future. It is assumed that a measurable cause-and-effect relationship exists between the independent and dependent variables for each equation in the model, although this assumption cannot be scientifically proved.

Forecasts are made by assuming future levels of the independent variables and solving for the dependent variable of the equation(s). If the assumptions are reasonable, and the equations are realistically constructed, then the econometric model may be a useful forecasting technique, the reliability of which can be tested. Since the equations are based on selected economic relationships, forecasting reliability depends upon the future being representative of past experience and the inclusion into the model of those independent variables which best explain the behavior of the dependent variable. The advantages of the econometric method are two-fold: a forecasting tool and a means of measuring interrelated variables have been provided.

II. Residential Electricity Demand Econometric Forecasting Model

This section presents an econometric model based on a study of the demand for residential electricity. The basic postulate is that residential electricity demand is a derived demand, depending on the use by consumers of electrical appliances (any electrical apparatus). In equation form, this derived demand for electricity may be stated in terms of the stock of electrical appliances owned by consumers at a given time[3], as follows:

(1) Residential Electricity Demand = f (Appliance Stocks)[4]

[1] Prepared by Phyllis Kline, Office of Economics, FPC, Washington, D.C.

[2] The word "demand" in this paper is used in the economic sense as opposed to usage of the term in the electric industry.

[3] Similar reasoning was developed by Professors Fisher and Kaysen in their book: *A Study in Econometrics—The Demand for Electricity in the United States.*

[4] Where "f" in the equations represents the usual mathematical statement: "a function of."

FIGURE I
RESIDENTIAL ENERGY SALES 1950-65

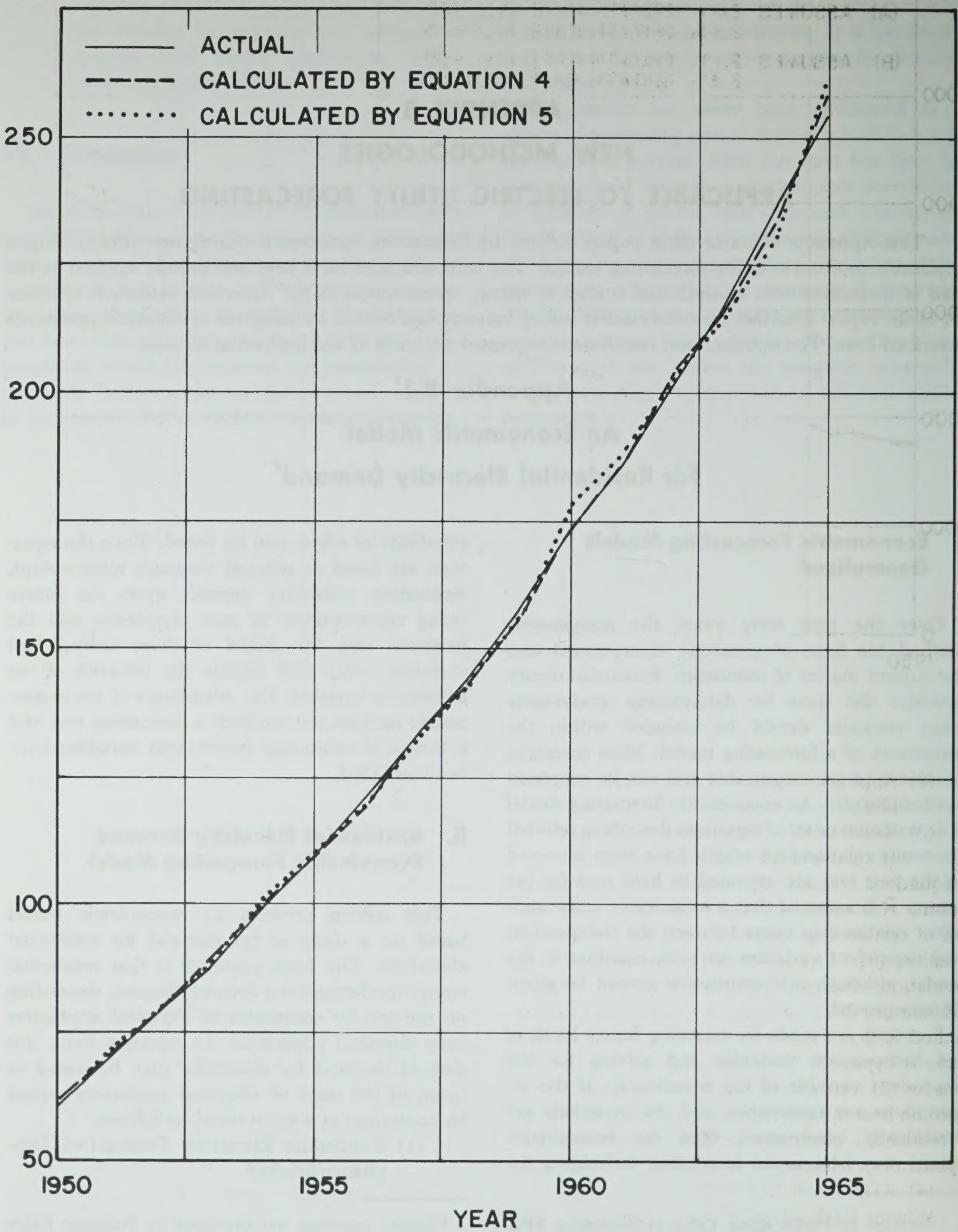
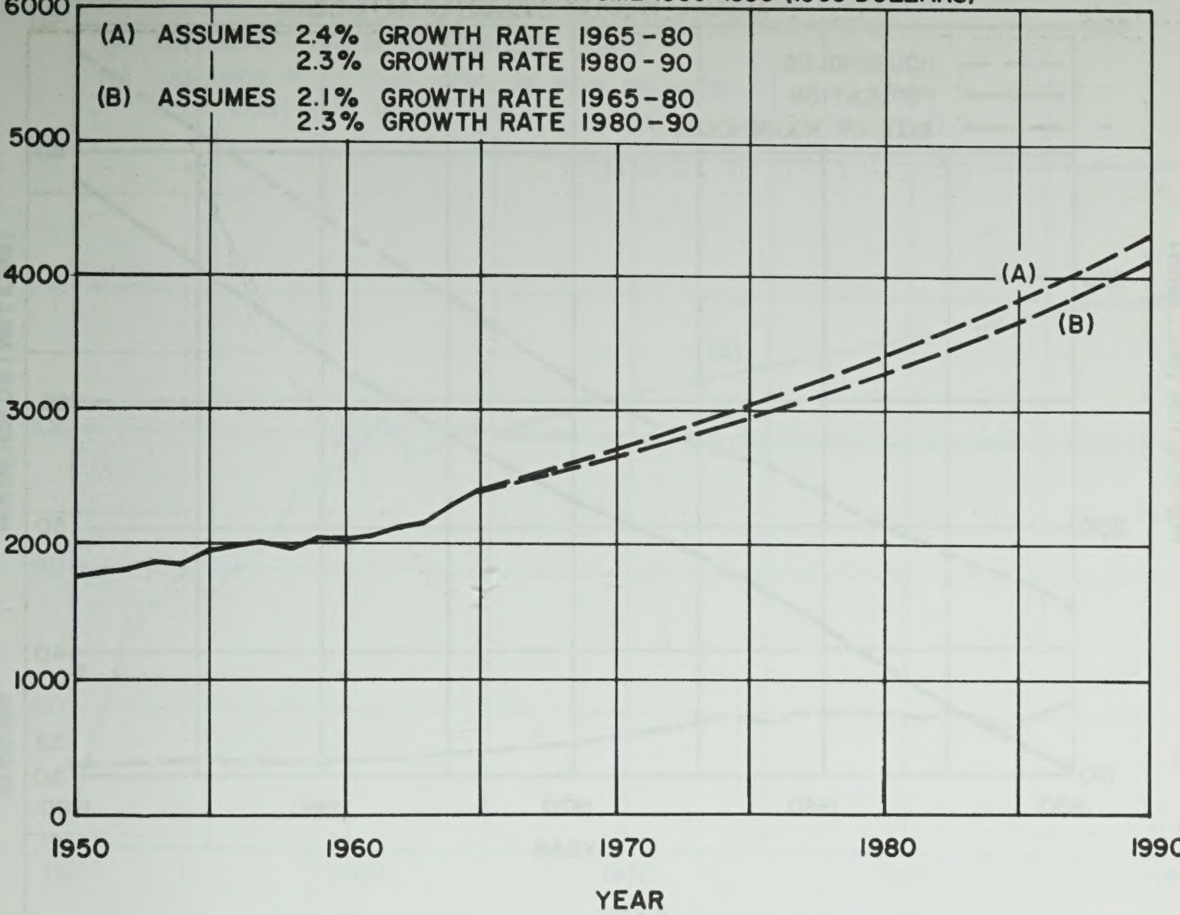


FIGURE 2

DISPOSABLE PER CAPITA INCOME 1950-1990 (1965 DOLLARS)



(2) Appliance Stocks = f (Explanatory Variables)

(3) Residential Electricity Demand = f (Explanatory Variables)

Equations (1) and (2) provide the logic for expressing residential electricity demand as a function of certain explanatory variables indicated by equation (3). Typical explanatory variables are population, income, gas/electricity price ratio, and number of households. The advantage of this method is that the need for measuring appliance stocks is bypassed. Two somewhat different equations for (3) were computed for the period 1950–65 based on least squares regressions of observed values of residential electricity demand and associated explanatory variables:

(4) $RDE = .496\ (10)^{-10}\ P^{3.7}\ I^{.88}\ R^{.69}$

Where: RDE = Residential Demand for Electricity

P = Population

I = Income

R = Gas/Electricity Price Ratio

The exponents associated with each of the independent variables are the derived elasticities. These elasticities may be interpreted as follows: A 1% increase in population, income or price ratio results, respectively, in approximately a 3.7%, .88%, or .69% increase in electricity, all other things being equal.

(5) $RDE = 3.23\ (10)^{-10}\ H^{3.3}\ I^{.97}\ R^{.82}\ S^{2.3}$

Where: RDE = Residential Demand for Electricity

H = Number of Households

I = Income

R = Gas/Electricity Price Ratio

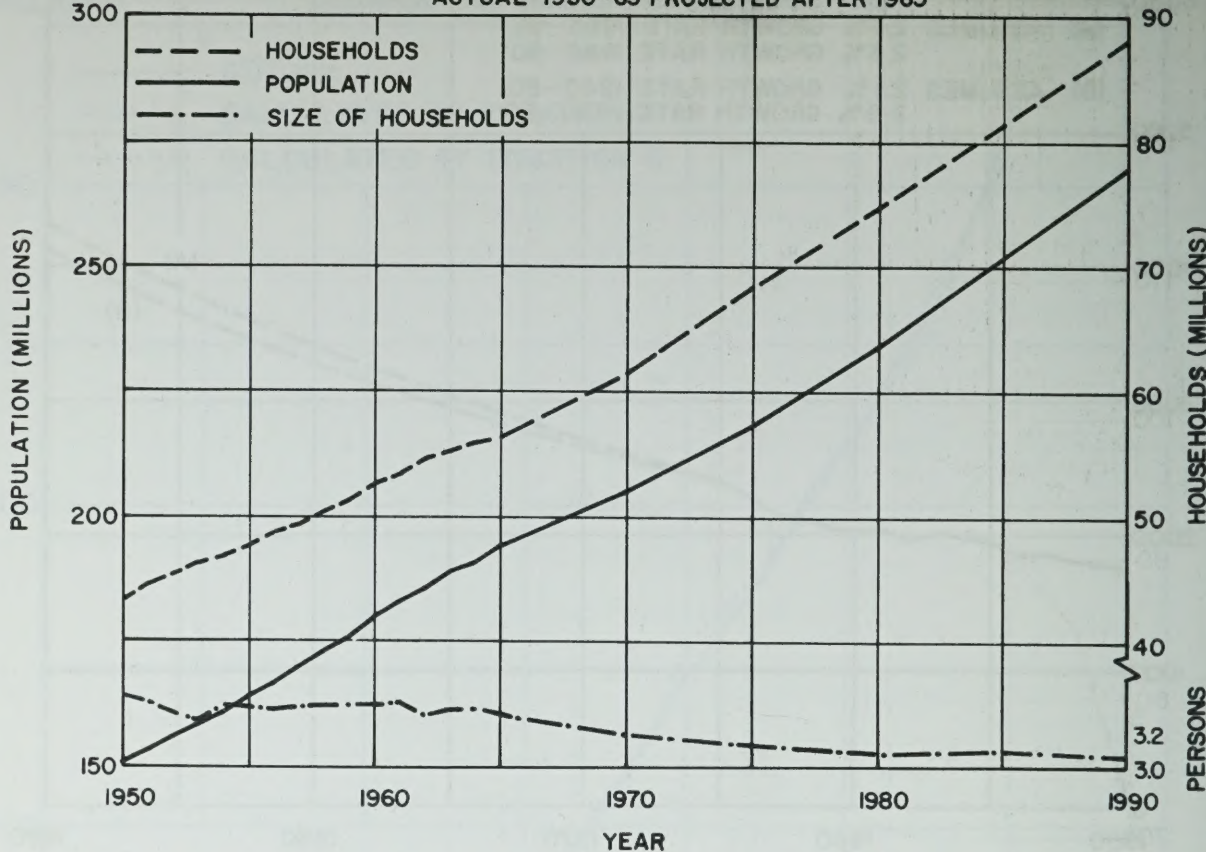
S = Size of Household

An exponent—elasticity association analogous to equation (4) applies here.

III. Forecasting with the Model

In forecasting for residential electricity demand, wherever possible future levels of the independent

FIGURE 3
POPULATION, NUMBER OF HOUSEHOLDS, SIZE OF HOUSEHOLDS, ACTUAL 1950-65 PROJECTED AFTER 1965



variables were taken from government projections. For the period 1965 through 1980 two income projections were used: level (I) at a 2.4% annual growth rate projected by the Office of Business Economics, Department of Commerce, and a more conservative level (II) at 2.1% projected by the FPC Office of Economics, with 2.3% applying for both series from 1980 through 1990. The resulting projections are shown on Figure 2. Projections of population are the "C" series of the Census Bureau, which also provided information on the number and size of households. (See Figure 3.)

Two projections of the price ratio were used: level (a) the past trend from 1950 through 1965 will continue and level (b) the future ratio will approximate the average of the last five years. (See Figure 4.) These assumptions yield four sets of residential electricity demand forecasts for each equation (4) and (5), as illustrated on Figures 5 and 6.

The highest forecast as given by equation (5), income (I), and price ratio (a) implies an average annual growth rate of approximately 8.3% for residential electricity demand from 1965 through 1990. The lowest growth rate of 7.0% is associated with equation (4), income (II), and price ratio (b).

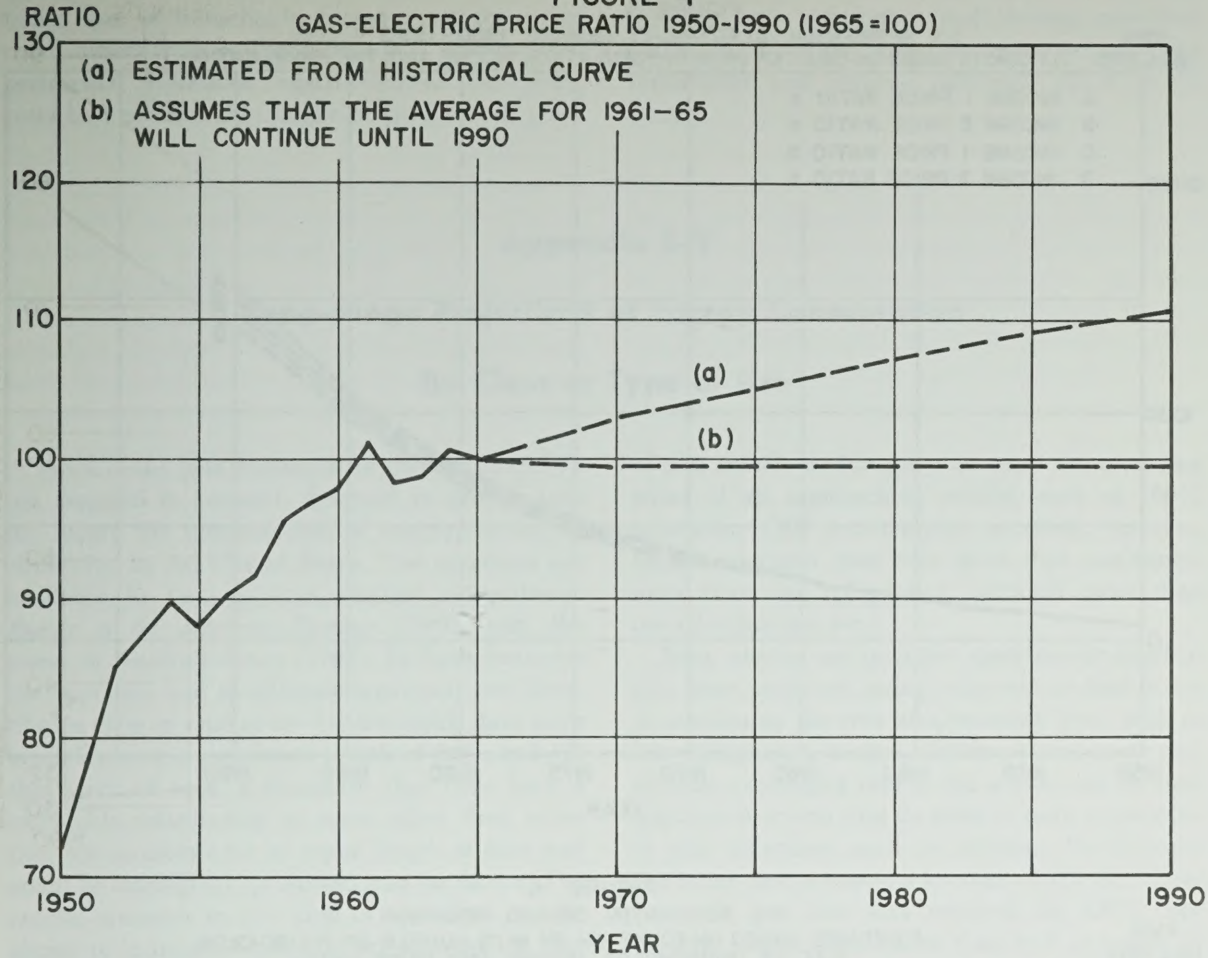
Forecasts of Residential Electricity Demand, 1970–1990

[Billions of KWH]

	Equation (4): based on population, income, and the price ratio			Equation (5): based on number of households, size of households, income and the price ratio		
	1970	1980	1990	1970	1980	1990
Income I:						
Price ratio a..	352	705	1446	365	790	1669
Price ratio b..	359	739	1553	374	837	1850
Income II:						
Price ratio a..	347	678	1392	360	757	1628
Price ratio b..	354	712	1494	368	802	1773

FIGURE 4

GAS-ELECTRIC PRICE RATIO 1950-1990 (1965=100)



The incorporation of the assumed price level into the model illustrates one of the favorable features ot the economic technique, since forecasting does not solely depend upon projections of income and population (households). Furthermore, separate estimates may be made of the influence of each variable on demand, thereby permitting the forecaster to vary the assumptions and measure the effect on his projections.

IV. Performance of the Model

Figure 1 and the following table illustrate the recorded annual residential demand for electricity for the period 1950–1965, associated with the calculated demand based upon recorded values of the independent variables. The dotted line after 1965 indicates that 1950–1965 data were used to calculate the 1966 and 1967 values.

The 1967 estimate based upon population income and the price ratio (Equation 4) differs from the recorded energy by only 0.2%. The other es-

Residential Electricity Demand, 1950–1967

[Billions KWH, recorded versus calculated]

Year	Recorded demand	Calculated	
		Equation No. (4)	Equation No. (5)
1950.......	61.2	61.8	61.2
1951.......	70.3	69.8	70.7
1952.......	79.0	78.9	79.0
1953.......	88.4	89.5	88.4
1954.......	98.7	100.0	100.7
1955.......	109.0	108.7	108.9
1956.......	121.4	119.4	119.1
1957.......	133.0	132.6	131.9
1958.......	144.0	143.0	142.7
1959.......	158.1	155.8	155.6
1960.......	173.7	173.7	177.6
1961.......	185.7	186.4	188.1
1962.......	201.7	203.8	203.1
1963.......	217.5	217.2	214.6
1964.......	236.6	233.8	230.6
1965.......	254.1	259.1	260.6
1966.......	279.6	279.4	282.3
1967.......	301.6	302.3	304.6

FIGURE 5

U.S. RESIDENTIAL ELECTRICITY DEMAND, 1950-1990

FORECASTS BASED ON EQUATION (4) WITH POPULATION, INCOME AND THE PRICE RATIO

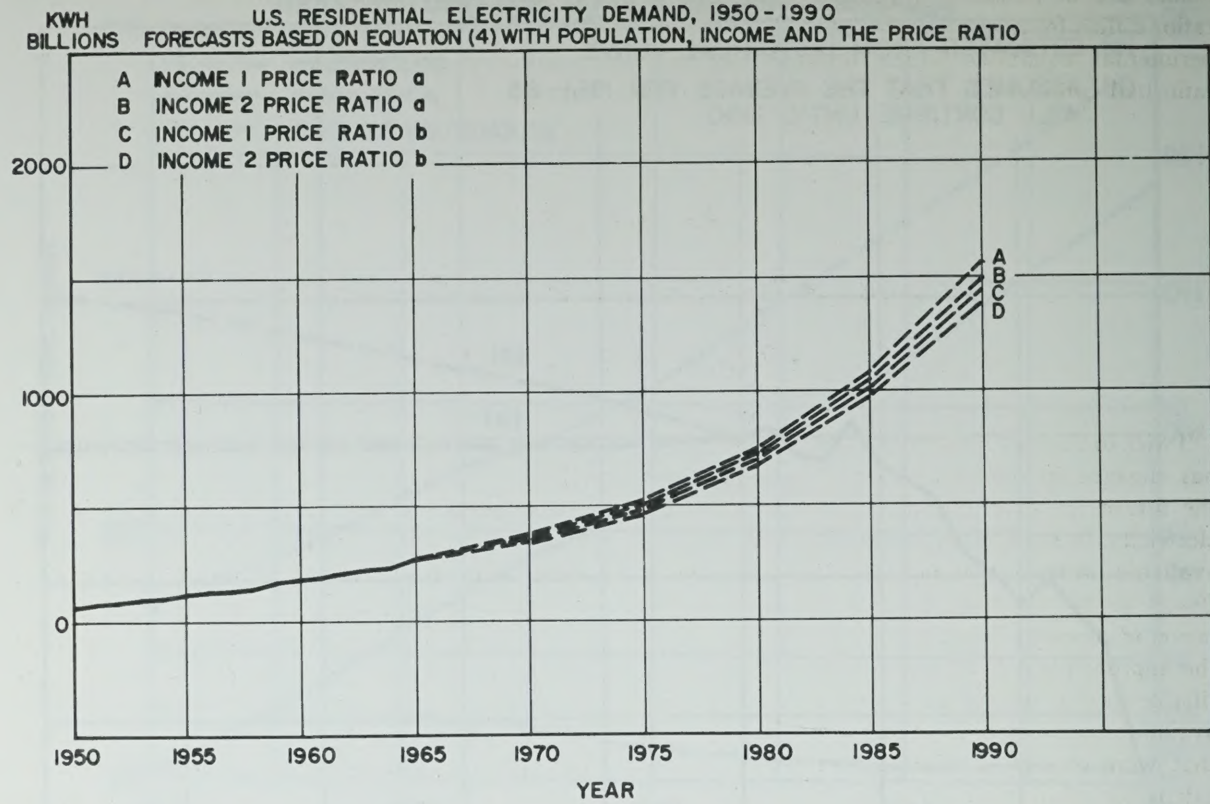
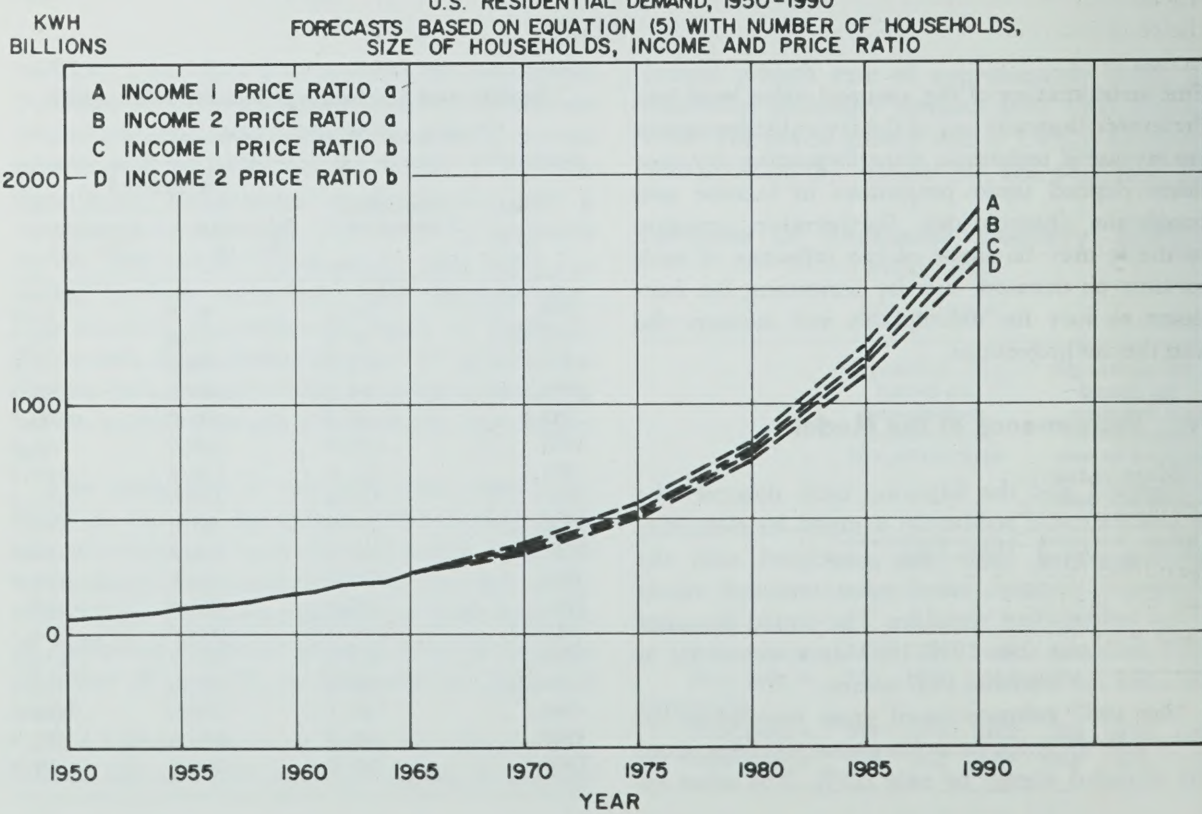


FIGURE 6

U.S. RESIDENTIAL DEMAND, 1950-1990

FORECASTS BASED ON EQUATION (5) WITH NUMBER OF HOUSEHOLDS, SIZE OF HOUSEHOLDS, INCOME AND PRICE RATIO



timate, utilizing projections of number of households, size of households, income and the price ratio, differs from recorded by 1.0%. The two experimental equations which omitted the price ratio had considerably larger errors for both 1966 and 1967. For 1967, as an example, the equation utilizing only population and income predicted 320.0 (6.1% error) and the equation utilizing households and income predicted 327.9 (8.7% error).

Appendix B-2[1]

Long-range Projections of Energy Consumption By Class or Type of Use

Twice in the past Resources for the Future (RFF) has engaged in research designed to project into the future the consumption of energy, including electricity, in the United States. The outcomes are available in two volumes entitled respectively: *Energy in the American Economy* (1960) and *Resources in America's Future* (1963). In both instances the approach was to estimate separately any identifiable class or type of use (1) for which data were available over a significant length of time, and (2) that were of such a character that they bore a calculable relationship to some other time series that was available for an equal length of time and could be intelligently projected into the future. The crucial elements in this kind of operation are the choice of individual uses that are selected for projection; a clear understanding of the makeup of the time series that are used; some confidence that the "reference series," i.e., the time series to which energy use is related, can be projected more confidently than the energy use series itself; and finally the ability to make a supportable guess as to the future relationship of the energy use series to the reference series. The following is a brief description of the major uses that were projected and the methods employed.

1. Residential Use

Major applications, such as lighting, water heating, cooking, air conditioning, space heating, radio, television, etc. were identified in terms of quantities being used, saturation rates, and annual use per appliance or application. The saturation rates were then projected, based on an inspection of past trends, and keeping in mind the retarding effect of an approaching ceiling, such as 100% saturation. (100 is not always a ceiling, however, since a customer may have more than one range, more than one refrigerator, certainly more than one television set, etc.)

Next, annual use rates per appliance or application were projected, using judgment to lead either to continuing the rate at a constant level, such as for refrigerators, ranges, clothes dryers, or to permitting a changing rate in the annual use for such appliances or uses that do seem to have a potential in that direction, such as lighting. To illustrate the latter case, a national average of 825 KWH per customer per year was assumed for 1960, contrasting with a little more than half as much 15 years earlier. For 1970 the annual figure was allowed to rise to 1075, and to 1325 in 1980. These are obviously rough judgmental levels, but the main point is to make some provision for increases, in some simple way related to the past experience, rather than to abstain from guessing altogether. Past records certainly show a substantial, though gradual, rise in this particular use-per-customer series.

To give other illustrations, in the case of air conditioning it was assumed that annual rates would slowly decline, reflecting (1) better insulation in newly built houses (aided in turn by the spread of electric heating), and (2) the extension of air conditioning to the cooler portions of the country, thus reducing national average use per year. Similarly, the annual usage rate for clothes dryers, which was set at 1300 KWH per year in 1960, was assumed to decline steadily through the balance of the century, based largely on the assumption of continuing increases in fast-drying fabrics. Average use of refrigerators and television

[1] Prepared by Hans H. Landsberg, Resources for the Future, Washington, D.C.

sets, on the other hand, were left constant for the balance of the century.

There is obviously much latitude both in the base year, and, much more so, in the projections. As for the base year, there are quite a number of sources available to choose from and while there is a good deal of variation among the sources the range is not so wide as to discredit the entire method. For those interested, the sources available, as of about 1960, are listed in *Energy in the American Economy*, page 620.

Once the saturation rate and annual consumption per appliance or use had been estimated, an independently derived projection of number of households or customers or both was then used to project total residential demand.

Probably the most troublesome element in the residential consumption in this approach was electric space-heating. Projections were calculated at the same time as were space-heating demand by gas, oil, and coal, and shares of projected energy consumption for space-heating by all sources. Specifically, the future stock of dwelling units was estimated by date of construction, and to each age category a rate of heating by electricity was applied that rose continuously from the base year level. The consumption per dwelling was estimated, then the relative shares of different types of electric heating (resistance vs. heat pump), next the efficiency for each type, and therefrom was derived the needed energy input per dwelling (or household). Multiplication by number of projected households, derived independently, yielded total demand.

Because it is certain that new uses will come into existence that are either very small now or not yet even on the drawing board, the RFF projections provided for a "miscellaneous" category which in the base year includes all not specially identified uses. This category was allowed to rise rather rapidly into the future, so as to reflect the as yet unknown uses. To illustrate again the annual use per household in 1960 was set at 330 KWH, comprising at that point only the miscellaneous uses already known. It was allowed to rise rapidly to 550 in 1970, 850 in 1980, and so on up to 1,600 by the end of the century. At that level, incidentally, the annual use exceeded that of electric ranges. Thus it is not a negligible quantity.

2. Commercial Use

Because of the diversity within this class accompanied by lack of data on specific users or uses, RFF made no attempt to subdivide the commercial class. Instead the time series for commercial sales was related to residential use. This was based on an inspection and analysis of the relationship of past commercial to past residential annual use.

The projection was made in two steps. A time series consisting of the ratio between commercial use per customer and residential use per customer was established and was projected into the future. The ratio applied to average residential use—previously projected—yielded average annual commercial use. Secondly, the future number of commercial customers was obtained as a constant ratio of the independently projected number of households, the rationale being a highly constant relationship between the two series in the past. From these two series—average commercial consumption per customer and the number of commercial customers—total commercial consumption was computed. (It may be remarked here that this rather simple approach, which seemed to be justified by past experience, has not held up well since 1960, owing to the much faster rise in electricity consumption per commercial customer in the sixties. It just so happened that RFF made its calculations precisely around the time when there was a major break in a long-time trend in the relationship between the two time series. For this reason an annual review of this kind of projection effort is highly recommended in order to have an early warning of such breaks.)

3. Industrial Use

For each of the two-digit S.I.C. groups of the FRB Index of Production a coefficient was established to express the relationship to an appropriate measure of electric energy consumption, as contained in Census Bureau statistics, both the Census of Manufactures and the Annual Surveys. Observed trends in the past were interpreted in the light of available knowledge of electricity use in the given group of industries and projected into the future on the basis of both graphic and judgment factors. These projected coefficients were then applied to independently projected index numbers of the FRB Index, separately for each group.

The only industry for which a different approach was utilized, was the primary metals, largely because of the importance of aluminum and elec-

trically-made steel and ferro-alloys. Basically, estimates were derived of future electricity consumption per unit of output for each of the major metals, based on past trends and fragmentary data on future technology. These unit-consumption factors were then applied to independently-derived future tonnage of each metal. In the case of steel, separate estimates were made for future electricity use in electric furnaces and in all other phases of the industry.

There is a question of whether all this detail is necessary. In fact, the earlier RFF study, *Energy in the American Economy*, used a simpler method in which the composite FRB Index—not its parts—was related to total industrial electricity consumption; the same technique of electricity consumed per point of the index was then used. There is probably something to be said for subdividing, if data permit, because on a regional or subregional basis some components of the FRB Index will be more significant than others and projecting on the basis of the index as a whole may be less satisfactory.

One of the crucial items, in which one has little to go by but a historical record and one's own judgment, is the extension into the future of the KWH used per index point of the FRB Index RFF used a record of eleven years—1947 to 1958—to establish a historical record and then used whatever judgment was available on future technology and efficiency to extend that time series into the future. The uncertainties in the projection of this coefficient are compounded with uncertainties in projecting the FRB Index itself, except that in this particular instance this was done as part of a projection of the entire economy so that there were certain control figures within which the individual projections had to fit.

Projections, industry by industry, of KWH per FRB Index point show the somewhat daring arithmetic that projection efforts lead to. For example, in the case of the food, beverages, and tobacco industry the coefficient (million KWH per index point) went from 170 in 1960 to 230 in 1980, based on what looked like a definite upward trend in the past. For the textile group it was left constant at 150, given the historical record and no specific indication that anything was in the wind to change it. In the case of paper and printing the coefficient was raised from 320 in 1960 to 425 in 1980. It was raised from 650 to 800, over the same period, for the chemicals industry, from 80 to 130 for the fabricated metal products industry, from 165 to 210 for the transportation equipment industry, but left constant at 70 for the entire 40 years of 1960 to 2000 for the electric machinery industry. In the last case, the coefficient between 1947 and 1957 never rose above 75 and never dropped below 65; it did suddenly jump to 90 in 1958, but it was not clear that it was a permanent break. Thus the decision to set the coefficient at 70 for the entire subsequent period. It is this kind of decision that is bound to create difficulties for those engaged in forecasting, but there is no safe way around them. To leave things as they are found in the base year surely would be a worse guess.

4. Other Uses

Although they are small, projections were also made for *street and highway lighting*, which was treated as a function of residential consumption. Historical records show that street and highway lighting has been declining relative to residential use, though more slowly in the recent than in the more remote past. A very slow decline was therefore postulated for the post-1960 period and the resulting coefficients were applied to previously projected residential consumption. There remained, then, the so-called public authorities category which was related to commercial consumption to which it had shown a rather systematic relationship in the past, declining slowly from about 18% immediately after World War II to somewhere between 12 and 13% in the fifties. The relationship had returned to what it was before World War II, and in that context the use of electricity by other public authorities was estimated on the basis of a fixed relationship of 12½% of commercial consumption.

It should be kept in mind that all these projections were made on a national basis. Some of them can undoubtedly be made on a regional basis and some on an even smaller area or pattern. But for others it will be difficult to secure the necessary data. In those instances, it may be necessary to go to some larger aggregates and abandon the use-by-use approach. On the other hand, individual utilities should be in a position to have far better consumption data for their service areas than those estimated by national organizations for the country as a whole. Thus there will be some offsetting advantages if the method described above is used in a subnational projection effort.

Appendix B-3[1]

Integrated Forecasting Using Input/Output Techniques

When faced with the task of preparing long-term forecasts for capital investment decisions, many companies have often just extrapolated history into the future. Sometimes this method works well enough but there are numerous instances of its failure. Can we identify where it will fail *in advance*? Can one utility profit from the experience of others? There are several new techniques which can probably be fit together to answer "yes" to these questions. Their combination for utility forecasting is unproven but seems sufficiently promising to describe.

This combination of techniques starts from economic forecasting, for it is the economy, not the weather, that determines the *growth* of utility sales. To forecast the economy of a region, that region must be seen as part of a larger whole, the nation. Consequently, this chain of techniques begins with a national forecast of the output of the various industries in the economy. Then the growth in national output is allocated to the various regions. In fitting the equations of the mathematical model used for this allocation one hopes to find a way for one utility to profit from another's experience. Next, given forecasts of the industrial growth of a region, we apply to them projections of the electricity used per unit of output. This process gives the industrial and commercial component of sales. From the industrial projections we also get projections of employment and income, and from employment, population. These, together with the utility's own projection of prices, then become the ingredients of a forecast of residential and public use sales.

Thus, the chain has four links: the national forecast, the regional allocation, the translation from industrial output to utility sales, and the derivation of residential and public sales. We shall explain the general idea of each of these.

National Model

The national model to be used for regional forecasting should contain considerable detail by industry, for the industrial composition of growth strongly affects the regional location of the new jobs. Such detail is available from interindustry—or input-output—forecasts. The hallmark of these forecasts is that they have built-in consistency with the technological connections between industries. For example, one may ask what would be the effect on the demand for electricity of an increase in interest rates and repeal of the investment tax credit? An input-output forecasting model can answer this question by calculating, first, the impact of these changes on investment, then these investment demands are translated into demand for specific types of machinery, and these machinery demands, into demands for the various metals, and the demand for metals, into demands for electricity used in their making. The effect on the total demand for electricity is not impressive, but for a utility serving a major steel plant, it is definitely noticeable. Projections of technological change can be incorporated in the national model.

This sort of connection-tracing is made possible by an input-output table. In such a table the economy is divided into a number of sectors. The table has a row for each selling sector in the economy and a column for each buying sector. A table prepared by the Department of Commerce for 1958 has some 95 sellers; a table for 1963 is expected by the time this report is published. It will distinguish over 350 sellers. In both tables, one of the sectors is Electric Utilities.

From current data, it is possible to bring a table much more nearly up-to-date than its base year. For example, from the electricity consumption statistics of the Annual Survey of Manufactures, a fairly accurate picture of the current pattern of industrial use can be seen. From this same source, trends in the use of electricity per dollar of an industry's output can be deduced. This use *per dollar* of output is called an input-output *coefficient*. Table 7 shows, in the first column, the 1966 cost of purchased electricity by selected manufacturing industries. The second column shows the rate of change of the coefficients anticipated in the University of Maryland in-put-output model. The third column shows the rate of growth of output of the buyer industry as predicted by this model.

[1] Prepared by Prof. Clopper Almon, Jr., and Prof. Curtis Harris, Jr., Bureau of Economic and Business Research, University of Maryland.

TABLE 7

Selected Entries for the Electricity Row of an Input-Output Table

Buyer industries	1966 purchases (millions) (1)	Annual rate of change of coefficient (percent) (2)	Buyer industry rate of growth of output (percent) (3)	Rate of growth of electric sales (percent) (4)
Dairy products	$56.8	.0	3.1	3.1
Canned and frozen foods	33.7	+3.4	4.8	8.2
Grain mill products	44.8	.0	3.2	3.2
Beverages	30.1	.0	4.6	4.6
Fabrics and yarn	118.0	.0	3.9	3.9
Rugs, tire cord, miscellaneous text	25.0	−1.1	5.9	4.8
Household furniture	26.0	+1.0	4.5	5.5
Office furniture	11.0	.0	4.7	4.7
Paper	202.0	+1.8	4.9	6.7
Printing and publishing	77.0	1.8	4.6	6.4
Basic chemicals	465.0	−5.0	3.9	−1.1
Plastics and synthetics	60.0	1.4	5.6	7.0
Drugs, cleaning and toilet items	32.0	.0	3.6	3.6
Petroleum refining	120.0	+1.2	4.1	5.3
Rubber and plastic products	105.0	.0	6.4	6.4
Steel	410.0	.0	3.3	3.3
Copper	23.0	.0	4.0	4.0
Aluminum	160.0	−3.6	4.8	1.2
Other metals	70.0	.0	3.7	3.7
Automobiles	137.0	.0	5.3	5.3

The fourth column shows their sum, the rate of growth of sales to this industry.

The Maryland forecasting model[4] begins from an updated table of input-output coefficients, projections of these coefficients and of labor productivity, the labor force, exports, imports, government expenditures, and interest rates. It also includes functional relationships between growth in output and investment and between income and the consumption of various items. The model requires an assumed after-tax income, calculates consumer spending on the products of each industry, adds in government net exports and investment demand, and then works this total final demand back through the table of input-output coefficients to calculate the total output of each sector. (After the first year, investment is calculated for the previous year's growth in output.) From the total outputs, employment is then determined and compared with the labor force. If it is too high, the tax rate is implicitly increased, and the assumed after-tax income reduced until employment equals a specified proportion of the labor force. The final result is a consistent table for a future year: the sales of each industry are accounted for by the purchases of consumers and other industries, and these purchases are consistent with the using industries' output and anticipated technology.

Regional Forecasts

To predict how well a particular area will participate in national growth, one should look at not only how well that particular area has done but also at how similar areas have done. (In this way, one utility can learn from the experience of others.) A systematic way to make such an analysis is offered by multiple regression with states as observations.

The model[5] starts with employment projections. The growth of an industry in a region is divided into two parts, the regional *share*—how much the industry would have grown in the region *if* it had grown at the national rate—and the regional *shift*

[4] Clopper Almon, Jr., *The American Economy to 1975*, Harper and Row, 1966.

[5] Curtis C. Harris, Jr., *State and County Projections, A Progress Report of the Regional Forecasting Project*, Bureau of Business and Economic Research, University of Maryland, 1969.

TABLE 8

Summary of Employment Projections and Population Migration by Standard Metropolitan Statistical Area (SMSA)

SMSA population range	Number of SMSA's in 1965	Employment in SMSA's (millions) 1960	Employment in SMSA's (millions) 1975	Percent change in employment 1960–1975	Number of SMSA's with employment growth rate less than national average	Net population migration necessary to achieve 4 percent unemployment rate (millions)[1]
Greater than 1,000,000......	29	25.5	32.5	27.5	19	−1.3
Less than 1,000,000.........	190	18.8	25.2	33.6	96	−0.2

[1] Difference between what the population would be in 1975 if there was no inter-county migration between 1965 and 1975 and what the population would be if there is 4% unemployment in each county in the SMSA, given the employment projections.

(or "competitive effect")—the difference between the industry's actual growth and the regional share.

The regional shifts are, of course, the center of attention. A variety of variables is used to explain them: the prior locational shifts of the industry in question, the locational shifts of the major supplying and selling markets, and the wage rates. The major industrial suppliers, the major industrial buyers, and final demand buyers are identified through the national input-output table; and when it is hypothesized that these technical inter-relationships also have locational ties, they are included as explanatory variables. For example, the changing location of the stone and clay products industry is partially explained by the changing location of the nonmetal mining industry, the major supplier, and by the changing location of the construction industry, the major buyer. When an industry produces final consumer goods, the changing location of population or personal income is used to represent the market.

Two typical employment equations are

Regional Shift of Petroleum Refining =
397. +.153 × Past Shift of Crude Petroleum Extraction
+.027 × Past Shift of Transportation
+.076 × Difference between local employment in Petroleum Refining and what it would have to be to have the national proportion in petroleum refining.
+5681 if the state is New York, New Jersey, or Pennsylvania.

Regional Shift in Primary Non-ferrous Metals =
−528 +.042 × Past Shift in Construction
+.170 × Past Shift in Primary Non-ferrous
−.499 × Difference between local employment in Primary Non-ferrous and what it would have to be to have the national proportion in this industry.
+3000 if the state had more than 5% of the nation's employment in this industry.

The next step in the regional model is to estimate population migration. The population of the state is allowed to grow at its historical birth and death rates and then the net migration is added to obtain estimates of population. Variables used to explain net migration are the shifting location of the resource industries (agriculture and mining), the shifting location of the manufacturing and construction industries, the rate of change in the location of total employment, and the net migration of the prior period.

The model then proceeds to personal income projections, which are made from the employment and population projections plus trends in annual earnings per worker by states for the major industries. Earnings are the product of the projected wage rate and employment, while other components of personal income—transfer payments and property income—are related to populations.

Finally, labor force estimates are derived by applying each state's labor force participation

TABLE 9

Summary Projections of Population and Employment by Population Size Group

Population range (thousands)	Number of county type areas in 1960	Population of all counties in group (millions) 1960	Population of all counties in group (millions) 1975	Civilian employment in all counties in the group (millions) 1960	Civilian employment in all counties in the group (millions) 1975	Percent change in employment 1960–75	Percent number of counties with percent change in employment <0	0–30	30–60	>60
>1,000..........	16	33.6	36.8	13.2	15.3	15.6	25.0	56.3	12.5	6.3
500–1,000........	49	33.0	42.7	12.6	16.8	32.8	4.1	63.3	20.4	12.2
100–500.........	239	49.3	65.9	17.6	24.5	39.3	7.5	43.5	27.2	21.8
50–100..........	292	20.2	26.4	6.9	9.4	37.1	4.1	43.5	36.3	16.1
10–50...........	1,652	38.3	46.0	12.7	16.0	25.3	13.0	54.3	24.2	8.6
<10............	822	4.9	5.8	1.7	2.0	20.9	20.8	51.6	18.0	9.6
Total.....	3,070	179.3	223.6	64.6	84.0	30.0	13.7	51.9	23.8	10.7

rate to the estimated population. This labor force less armed forces is matched with civilian employment to obtain estimates of unemployment.

County projections have been derived using the same procedure used to obtain the state projections. The state employment projections by industry however, had to be aggregated to 20 industries then used as controls to distribute the employment projections to counties within the state. Each state has its own set of industry location equations. In other words, each state is treated as the nation was in the state model.

Tables 8 and 9 summarize some of the results produced with the current model. The projections assumed that the national unemployment rate will be 4% in each year between now and 1975. The tables show that the very large counties and the very small counties are expected to have relatively slow rates of growth in employment, while counties in the 100,000 to 500,000 group have high growth rates on the average. They also show that present day SMSA's will need either a net outmigration of people or a faster rate of employment growth if they are to achieve full employment. Given the employment projections shown on Table 8, the natural rate of increase in population in SMSA's is too fast to achieve full employment.

The forecasts made by these methods are by no means perfect. They have all the shortcomings inherent in the data on which they are based, which is basically employment data. The present forecasts are derived from the population census and suffer from the long lag between censuses and from the problems of converting employment into production. The next generation of forecasts will be based on annual state and county employment statistics derived from Social Security reports and on state production statistics from the Census of Manufactures. Here the time lag is shorter, but the census disclosure rule often makes the data less complete than one might wish. In no case will the equations have "inside information" on what new plants may have already decided to come to an area. But in the past, they would, on the average, have out-performed any of the simple assumptions frequently made such as that the region will continue to grow at the same rate as in the past or that its industries will grow at the national rate or that they will deviate from the national rate by the same amount as in the past.

Industrial Use

The next step is to translate regional growth into industrial use of electricity. To our knowledge, this translation has not yet been made at the regional level, but the methods used at the national level by Resources for the Future[6] indicate the approach.

Residential and Commercial Use

Because the regional forecasting model provides projections of personal income and population, these become the principal ingredients of residential and commercial projections. There are basically two approaches, the use-by-use analysis and the econometric equation.

[6] In the volumes *Energy in the American Economy* and *Resources in America's Future*. See Appendix B–2.

The use-by-use approach, used by RFF at the national level (See Appendix B–2), estimates a number of individually identified applications, such as space-heating, air conditioning, lighting, water heating, cooking and so on.

The econometric equation approach to forecasting residential use described in Appendix B–1 does not distinguish between the various applications of electricity but develops a mathematical relation between total residential use and such "independent" variables as number of households, income per capita, size of households, and the ratio of electric prices to gas prices. Such equations have frequently been fit for national data and forecast quite accurately. For use in regional forecasting, it would be better to have equations which had been fit to observations on different utility territories as well as over time. The regional forecasting model described above has developed the necessary independent variables for the estimation of such an equation; it also provides forecasts of these variables for the future.

Conclusion

All of the approaches described here are still definitely experimental in their application to forecasting for individual utilities. There is good logic behind them, however, and a great deal of basic work has already been done. Trial applications are now within the reach of individual companies.

APPENDIX C

ANNOTATED BIBLIOGRAPHY ON ELECTRIC POWER SYSTEM LOAD FORECASTING AND RELATED SUBJECTS

The Committee has found the books and articles listed in this Appendix to be helpful. The list represents a cross-section of statistical, analytical and forecasting techniques. Several of the entries are referred to in the body of this report.

There are many other books, periodicals and reports which are equally as useful; their omission from this bibliography does not constitute a value judgment by the Committee. In most cases the references are available from local libraries and the publishers. The Engineering Societies Library, United Engineering Center, 345 East 47th Street, New York, New York, 10017, can provide photoprint or 35 mm microfilm copies of articles and technical papers. Books may be borrowed in person or by mail by members of founder and associate engineering societies.

BASIC STATISTICAL METHODS

Applied General Statistics, Croxton and Cowden, Prentice-Hall 1955.

For beginning students in statistics with emphasis on business applications. It is strong in the areas of visual concepts, time series, curve fitting, and correlation analysis.

Statistical Methods, George W. Snedecor, The Iowa State College Press, Ames, Iowa, 1956.

Pioneering text in non-calculus applied statistics. While the subject matter is oriented to agricultural topics, the treatment of analysis of variance and chi-square is good.

Mathematics of Statistics, Kenny and Keeping, D. Van Nostrand 1954.

This text is mainly concerned with the mathematical treatment of statistics. References at the ends of many of the chapters provide the forecaster additional sources for information.

Statistics as Applied to Economics and Business, Wessel and Willett. Holt, Rinehard, & Winston 1963.

Excellent text for the individual who has had little mathematical training. The authors have employed detailed explanations to clarify the meaning of complex relationships. Good coverage is given to the construction and use of index numbers.

Statistics, an Introductory Analysis, Yamane. Harper & Row.

This text is mainly for advanced students in business and economics. Emphasis is placed on the theoretical aspects of statistics. Excellent material for forecasts involving correlation analysis and multiple linear regression.

Business and Economics Statistics, Spurr, Kellogg, and Smith, Richard D. Irwin, 1961.

This text is designed with major emphasis on the use of statistical methods in analysis of business and economic problems rather than on theory or mathematical deviations. Such subject matter as collection of data, sample surveys and methods of presenting facts in tables and charts are given good coverage.

Introduction to Mathematical Statistics, Paul G. Hoeb, John Wiley & Sons, 1954.

Landmark text on statistics requiring calculus as a background. Its main value is to relate statistics to mathematical probability.

Electronic Computers and Business Indicators, Julius Shiskin, Occasional Paper No. 57. National Bureau of Economic Research, Inc., 1957.

This paper presents a description of the basic Census II Seasonal Adjustment Program used to analyze economic time series in much greater detail than was formerly possible. Although designed to process monthly data, the program is also adaptable to quarterly time periods. Each economic time series is depicted as consisting of four components, trend, cycle, season, and irregular such that raw-data = TXCXSXI. The past behavior of some of the more commonly used economic time series is noted. The starting point, as in most seasonal adjustment techniques, is a moving average. Through a series of computations and smoothing procedures seasonal and irregular components which average out to 100% are calculated. In addition, seasonally adjusted data containing a combination of trend, cycle, and irregular elements and a smoother trend-cycle combination are also computed. While a number of other tables are output, printouts of the aforementioned information are the most important. Ready access to this information is very important to economists for analyzing and forecasting business activity.

Statistical Forecasting for Inventory Control, R. G. Brown, McGraw-Hill Book Co., Inc., 1959.

This text, while designed specifically for inventory control, treats certain selected topics having applications for electric utility energy forecasting. Of particular interest is the following subject matter: (a) smoothing by moving averages; (b) exponential smoothing; (c) second order smoothing and forecasting; (d) weighting historical data; (e) autocorrelation (time related correlation); (f) uncertainty of forecasts; (g) seasonal, cyclical, trend, and irregular factors; (h) probability distributions; (i) transforms for dis-

crete variables; and (j) Monte Carlo simulation (generation of random numbers). The information contained in this text, therefore, is of a technical nature and valuable to those who design computerized methods for analyzing, forecasting, and simulating time series, and to those who use data processed by high-speed computers and find it necessary to understand the computational methods involved.

PITFALLS OF STATISTICAL ANALYSIS, W. A. Black. Public Utilities Fortnightly, Nov. 21, 1968, pp. 25–31.

Discusses the misuses in four types of statistical analysis. The areas covered are: interpretation of data, regression analysis, ratios and T & D expense equations.

GENERAL BUSINESS FORECASTING

HOW BUSINESS ECONOMISTS FORECAST, William F. Butler and Robert A. Kavesh (Editors), Prentice-Hall, Inc. 1966.

Prepared with the assistance of members of the National Association of Business Economists, this book consists of a series of short essays directed toward businessmen which reveal how leading forecasters fuse the sciences and arts of their fields to develop useful forecasts. In most of the chapters the major concern is on short-term (12 to 18 months) techniques, but, where relevant, reference is made to procedures and implications pertaining to long-run projections.

Part I deals with the major approaches used in business forecasting: the use of models (with or without computers) and econometric methods; the "indicators" approach and the related diffusion indices; and the use of surveys of all forms in predicting change. An excellent guide to the types of data and their sources is included.

Part II details procedures for forecasting Gross National Product in terms of both the total and its component parts.

Part III brings the analytical framework down to the level of the industry and individual company. Techniques for preparing a sales forecast for a company are spelled out. The focus is then shifted to specific industries and the procedures to be utilized in forecasting their future; separate chapters cover the energy industry and the appliance industry.

Part IV covers forecasting in the financial area.

Part V focuses upon how to use and evaluate forecasts. Much of the work of a forecaster consists of interpreting his (and other) projections to management. This section cites the problems and potentials in these areas, as well as the uses and abuses of forecasts.

THE DUALITY BETWEEN LONG-TERM PLANNING AND FORECASTING, W. Russel Yurchak and Elmer C. Bratt, Business Economics, Vol. III, No. 3, Summer 1968.

Long-term forecasting supplements long-term planning by helping a company check the viability of its goals and strategies against what is expected to happen in the outside world. Although long-term forecasts are necessarily imprecise, they nonetheless can be effective and provide an integral part in the formulation of any long-range plans. Econometric methods, along with trend extrapolations, have helped improve forecasting methodology in recent years, but mechanical methods by themselves are inadequate. Experienced judgment is also needed.

WHY FORECASTS FAIL, J. T. Jensen, Management Methods, August 1959, pages 50–59.

A realistic definition of forecast failure is not just when specific forecast quantities are not realized, but rather when the policy indicated by the forecast is in error. Causes of such failure are inherent not only in data availability, but in lack of understanding on part of both forecasters and management. Present policy and over enthusiasm or depression can exert unwarranted pressures on the forecaster and the forecast. Judgment and objective analysis of existing circumstances are necessary in the production of a good forecast.

HOW TO LIE WITH STATISTICS, Darrell Huff, W. W. Norton & Co., New York, 1954.

Provides a useful perspective for judging the statistics produced by others as well as clues to the forecaster's methods of presenting the results of his work so that they are likely to be interpreted correctly.

THE STRUCTURE OF THE U. S. ECONOMY, Wassily W. Leontief, Scientific American, April 1965, pp. 25–35.

Popular article describing input/output technique for quantifying the transactions between sectors of the national economy. A number of large industrial companies have constructed input/output tables of their companies to trace the mutual interdependence of their many divisions; some have also coupled their internal corporate tables to the national economy.

LONG RANGE FORECASTING METHODOLOGY, Martino, J. P. and Oberbeck, T. (Editors), a symposium held at Alamogordo, N. Mex., Oct. 11–12, 1967 (available from U.S. Department of Commerce Clearinghouse Document AD-679-176).

A compendium of papers on state-of-the-art techniques for long-range forecasting, including discussions. Papers of particular interest to utility forecasters include "Demographic Projection Techniques", "Technological Forecasting and its Role in Planning", "Long Range Projections of Labor Force", and "Anticipating Socioeconomic Consequences of a Major Technological Innovation."

ENERGY IN THE NATIONAL ECONOMY

ENERGY IN THE U.S.: SOURCES, USES, & POLICY ISSUES, H. H. Landsberg & S. H. Schurr, Resources for the Future, Inc., Random House 1968.

This book provides a nontechnical, fairly broad repository of information about the place of energy in the American economy, its past and its prospects. Written primarily to be used as an introduction to the field of energy in the United States.

RESOURCES IN AMERICA'S FUTURE/PATTERNS OF REQUIREMENTS AND AVAILABILITIES 1960–2000, H. H. Landsberg, L. L. Fischman, J. L. Fisher, Johns Hopkins Press, 1963.

Projections of America's natural resources are made not only at a medium range, but also at a possible high and low range.

Estimates of demand and supply are projected in 3 steps: (1) future requirements in broad areas of human needs and wants: food, clothing, shelter, heat, power, durable goods, transportation, recreation, etc. (2) Quantities of specific products needed to satisfy demands: crops, lumber, water, mineral fuel, metals, chemicals, etc. (3) Adequacy of the resource base with comparison to the nations total resources—and where pertinent, with the worlds.

Although primarily economic, this study also takes account of technological, social, and political factors.

An Energy Model for the United States, W. E. Morrison and C. L. Readling, U.S. Department of the Interior, Bureau of Mines, July 1968.

A simplified energy model for the United States is presented for the years 1947 through 1965. Basic models are used in the estimation of intermediate and long-range shifts in energy demand and supply. Historical data are presented for 1947 to 1965 in the form of integrated energy balances between sources, and consuming sectors. Conditional projections of historical trends of energy demand and required supply are made for the period 1966 to 1980. Long term contingencies and technological forecasts to the year 2000 are also discussed. These cases assume technological changes or innovations that produce major shifts in the long term pattern of energy consumption and the mix of required resources.

BASIC DATA SOURCES

A Directory of Information Resources in the United States (General title), Library of Congress, National Referral Center for Science and Technology, U.S. Government Printing Office.

The National Referral Center has compiled several directories which identify significant information sources in the fields of science and technology. The first directory, *Physical Sciences—Biological Sciences—Engineering*, was issued in 1965, followed by *Social Sciences* and *Water*. Each directory lists sources alphabetically by organization name; it also contains a detailed subject index. Sources include not only governmental agencies but industry associations, technical societies, libraries, and private corporations willing to extend their information services beyond their own organizations. The Referral Center expects to update the directories periodically; beyond simply cataloging sources the center has also been given the responsibility of acquiring information describing the specialized capabilities of the data source organizations and to provide guidance to the public in the use of the data which is available. Referral requests may be made by calling Area Code 202-967-8265, or by writing to the National Referral Center for Science and Technology, Library of Congress, Washington, D.C., 20540.

Long Term Economic Growth 1860–1965, U.S. Department of Commerce—Bureau of the Census, U.S. Government Printing Office, 1966.

This publication provides a compendium of data portraying the growth of the American economy. A series of graphs summarize the long-term performance of key indicators; these are supplemented by annual Data in tabular form useful for a variety of economic studies to support forecasting activity. Data included in the compendium originated in various public source materials from both Government and non-Government agencies and individuals.

Directory of Federal Statistics for Local Areas—A Guide to Sources—1966, U.S. Department of Commerce—Bureau of the Census, U.S. Government Printing Office.

A comprehensive guide to current sources of Federally published statistics for governmental and socio-economic units below the State level. The major units for which references are given separately are Standard Metropolitan Statistical Areas, counties and cities. Other types of areas are indicated for those publications that cover them.Data sources of interest to utility system forecasters include:

- Population
- Climate and Physical Environment
- Construction and Housing
- Labor and Employment
- Income and Earnings
- Prices
- Commerce and Trade
- Manufacturing

Preliminary Report on Economic Projections for Selected Geographic Areas, 1969–2020, Water Resources Council, Washington, D.C.

The Water Resources Council is an interdepartmental agency created by the Water Resources Planning Act of 1965.

Bibliography and Digest of U.S. Electric and Total Energy Forecasts, 1970–2050, Statistical committee, Edison Electric Institute, New York, N.Y.

Bibliography and summaries of published U.S. electric and total energy forecasts, summaries of several economic factors underlying forecasts and a synopsis of each forecast. The material describes the purpose, scope, assumptions, methodologies, and principal conclusions of each forecast studied. Shown in the appendices are several tables of energy conversion factors and forecast assumptions considered useful in energy forecasting.

STATISTICAL METHODS APPLIED TO UTILITY FORECASTING

An Econometric Model for Electric Utility Forecasting, David N. Reps, Westinghouse Electric Corp., Proceedings of the American Power Conference, March 1962.

Underlying this computerized model is the assumption that the electric utility planning process contains two parts: policy making and system planning based on policy making derived from business forecasting. This model deals with the business forecasting problem, and is mathematically structured in terms of (1) revenues and (2) earnings, which in turn are functions of such variables as operating income, net and gross investment, energy sales, capital and operating costs, taxes, and price (note: finer breakdowns are incorporated). Economic uncertainties on an annual basis such as load growth, future costs, and future technologies are systematically quantitized and serve as inputs to the model. Computerized outputs expressed as annual functional forecasts of (1) and (2) above provide a basis for policy making. Computer time may be minimized by the use of good judgment in selecting inputs since relevant policy making is dependent upon a variety of output forecasts which, however, should be prudent and reasonable. In this manner, policy making can serve as the basis for system planning by optimizing the uncertain revenues-earnings dichotomy consistent with management's perspective on changing economic conditions.

Forecasting Peak Demand for an Electric Utility With a Hybrid Exponential Model, Gordon K. C. Chen and Peter R. Winters, Management Science, Vol. 12, No. 12, August 1966, pages B-531–536.

This paper discusses forecasting peak load demand, one day in advance, for an electric utility, but its main purpose is to illustrate the combination of the exponential adaptation principle with modified rules-of-thumb being successfully

used by the electric company. The results indicate that although the company is already doing a good forecasting job, the hybrid exponential model, in simplest form, does even better, although it uses only a portion of the data that is available and used by the company.

Load and Capacity Models for Generation Planning by Simulation, Baldwin, Hoffman, DeSalvo, and Plant, Public Service Gas and Electric Co. and Westinghouse Electric Corp., AIEE Transactions, Power and Apparatus Systems, August 1960.

An econometric computerized model for simulating daily operating performance for as much as twenty years into the future is analyzed. The mathematical model is essentially a representation of the Public Service Electric and Gas Company power system and the power pool to which it is interconnected.[1] It describes the reactions of the power system to external stimuli such as load growth and also such characteristics as spinning-reserve policy and maintenance programs. Human decisions which affect power system operation and development are included in the model as formalized rules. Submodels generate the daily loads which confront the simulated system capacity and describe that capacity and the amount forced out (by probability technique) and the amount scheduled out (by human decision) with associated time durations. A long-term trend of June peaks is the starting point. Seasonal, daily, and probability factors are applied in order to derive daily peaks. Analysis may then be made of demands on the system versus available capacity.

[1] For a description of all the planned maintenance of the pool as a whole, see *Mathematical Models for Use on the Simulation of Generation Outages. III—Models for a Large Interconnection*, Baldwin, Garner, Hoffman and Rose, Ibid., 1959 (February 1960 section), pp. 1645–1650.

Study in Econometrics—The Demand for Electricity in the United States[2], Fisher and Kaysen, North Holland Publishing Co., Amsterdam, 1962.

This text presents an analysis of USA electricity demand elasticity; that is, the relationship between changes in the price and demand for electricity. Short-run residential-commercial demand for the period 1946–57 was found to be price inelastic, with changes in price not being a factor inducing changes in demand for electricity. A similar conclusion was found to apply for the long run, where changes in population, changes in the number of wired households, and the number of marriages were among the more important determinants for residential-commercial electricity demand. For industrial electricity demand, for the short-run case (assuming constant technology), statistical evidence generated for 1956 indicated the presence of price elasticity; that is, demand tended to be responsive to changes in price. In the long run technology will be changing but very little is known about the mechanics of this change. Statistical evidence generated for the period 1946–57 indicated, on balance, "technological change was either neutral or acted to increase the importance of electricity for industry as a whole."

[2] Summation of a review by Damodar Gujarati, Public Utilities Fortnightly, pp. 20–21, Jan. 30, 1969.

Probability Approach to Electric Utility Load Forecasting, James H. Latham, Jr., Dean A. Nordman, Senior Member, IEEE, E. Curtis Plant, Senior Member, IEEE, and John S. Voorhis, Member, IEEE, IEEE Transactions on Power Apparatus and Systems-Vol. PAS-87, No. 2, February 1968, pp. 496–504.

A sound theory of forecasting may be defined in two steps. The first step is to separate the whole into components that are more easily analyzed and reasoned than the whole. Previously existing techniques supplemented by new applications of regression analysis (1) are available to solve this step. The second step is to forecast the components and to reunite them to obtain a forecast of the whole. A digital computer program that has been developed to solve this second step will be discussed. Most significant in this new load forecasting program is the addition of another dimension—the probability dimension. The user of this program expresses to the program his uncertainty of the component forecasts, and it generates the resulting uncertainty of the final whole forecast. The required probability theory and methods of expressing uncertainty are stressed.

WEATHER INFLUENCES ON FORECASTS

Applying Weather Data to Utility Operations, P. H. Kutschenreuter and R. G. Beebe, Environmental Science Services Administration, Weather Bureau, Transmission and Distribution, April 1968.

Routine services of the Weather Bureau now available are described, evaluated for accuracy and the procedure to obtain available services is explained. New programs are planned for the future. The services of industrial meteorological consultants are available to utilities to supplement Weather Bureau data. The use of professional meteorological assistance will increase the probability that timely and comprehensive use will be made of weather information.

The Role of the Weather Correction in Load Forecasting, A. Thomas and J. Drummond, Consolidated Edison Co., E.E.I. Bulletin, August 1953.

This report analyzes Consolidated Edison's weather experience with respect to the following load forecasting factors: (1) long-run trend; (2) short-run situation; and (3) composition of the system load. Available weather data were limited to the interval 1950 through early 1953, and were restricted primarily to light intensity (cloud cover) and temperature, including both wet and dry bulb readings. Annual peak demand for the system occurs in December at about sunset, but extensive cloud cover tends to advance the timing of the peak about thirty minutes and increase the annual peak magnitude by 100 MW. Cloud cover, therefore, induces variations in peak demand from the trend. For the short run, seasonal factors apply, with demand declining through April, recovering to a summer plateau subject, however, to considerable variation induced by temperature variations, then rising to a winter peak. Easter, Passover, national political conventions, severe storms, and other special events can distort the seasonal pattern. With respect to the composition of the system load, temperature studies permit the isolation and examination of such segments of total demand as the air conditioning and heating components. By identifying these temperature-sensitive components, other segments of the system load, such as TV, can also be analyzed.

How Philadelphia Electric Improves Accuracy of Daily Load Forecasts, S. S. Clair and W. S. Einwechter, Philadelphia Electric Co., Electric Light & Power, April 1968.

The load of Philadelphia Electric is presumed to be composed of the following: (1) Base, a major fixed component for any particular hour of the day and reflecting the business cycle; (2) Weather Component, the major variable

component reflecting the effect of weather; and (3) Special Component, the minor variable component reflecting irregular events. The hourly base load is established at 65° F dry bulb temperature and 75% relative humidity, with Saturday, Sunday, and weekdays each possessing a definite pattern. The base load, therefore, can be evaluated and weighted by a weather factor incorporating temperature, humidity, light intensity, wind speed, barometric pressure, and heat buildup or retention. The day is divided into four periods, for which weather forecasts from a private service and the U. S. Weather Bureau are secured. The weather factor in the form of charts and graphs (nomograph technique) is systematically applied to the base load. Corrections of various magnitudes for the special component (strikes, popular TV events, snowstorms, etc.) can be reasonably estimated independently and applied to the load forecast. In this manner peak demand for the four daily periods can be accurately estimated and spinning reserve optimized, assuming the weather forecasts are accurate.

Special Weather Forecasts Aid Utility Operation, L. E. Brosche, General Weather Center, Detroit, Mich., Electrical World, Aug. 14, 1967; pp. 29–31.

Accurate and specialized weather forecasts offer invaluable aids to electric utilities in planning their operating and maintenance schedules. Short-range forecasts, which are developed as twenty-four hour forecasts, are based on empirical formulas and are useful for scheduling generation or assigning construction and maintenance crews. The seasonal-type predictions, which cover nine months to a year in advance, may be factored into such programs as budget planning, estimating revenue, and scheduling maintenance. The article demonstrates that as a result of using weather variables and their effects, a high degree of accuracy can be obtained.

WEATHER INFLUENCES ON FORECASTS

The Relationshp Between Summer Weather and Summer Loads—A Regression Analysis, G. T. Heinemann, D. A. Norman, Senior Member, IEEE, and E. C. Plant, Senior Member, IEEE, IEEE Transactions on Power Apparatus and Systems, November 1966, Vol. PAS 85, No. 11, pp. 1144–1154.

When summer air conditioning contributes significantly to an electric utility's system peak load, it is useful, for load forecasting purposes, to separate total system load into two components: temperature-sensitive load and non-temperature-sensitive load. Examination of historical data indicates that temperature-sensitive loads depend not only upon coincident but also antecedent weather conditions. Regression analysis techniques using a digital computer have shown that the combined effect of these weather conditions can be expressed by one composite weather variable (WV). Total system load can then be expressed as Basic Load plus the product of WV times a coefficient of air-conditioning saturation. Results obtained by application of this method to historical data (1949–1964) of Public Service Electric and Gas Company are presented.

Electric Heating in the Tennessee Valley—A Pattern for the Future, William R. New, Tennessee Valley Authority, Proceedings of the American Power Conference, 1957, Vol. XIX.

In the ten-year period prior to 1957, residential electric heating increased from 2 percent to 14 percent on the TVA system. During this period the rate of growth of the amount of load and energy subject to temperature change declined while the rate growth of heating consumers increased. The main reason is the increase in non-heating usage of electricity which helps to meet the heating requirements. Also, the load factor of electric heating load increased as the saturation increased. Electric heating is a very beneficial portion of the total TVA load. Homes with electric heat will not use any other types of energy.

Report on Load Diversity—December 1968, Subcommittee on Load Diversity of the Committee on Coordinated Area Operations. Edison Electric Institute, New York.

Presents results of analysis of hourly load data from approximately 160 utility systems for years 1962 through 1966. Objective is to identify the amounts of load diversity among various combinations of systems for forecasting and planning purposes. Load diversity due to difference in clock time was found to be low during the summer months due to the nature of temperature-sensitive loads which remain at relatively constant high values for several hours. This is particularly significant with the emergence of a national summer peak.

Probability Technique Adds New Meaning to Demand Forecasting, Carl G. Kind, Union Electric Co., Electric Light & Power, January 1969.

A proposal is presented for forecasting Union Electric Company summer annual peak demand by analyzing separately the weather sensitive and non-weather sensitive (base) components in the context of uncertainty. About ⅜ths of consumer demand is weather sensitive but this component is growing the fastest and demonstrates the greatest variability as a result of the expanding air conditioning market. By blending a computer-oriented, statistical analysis of historical weather (work day only) and business activity data with human judgment and the air conditioning market, weather sensitive and base demands are systematically evaluated and forecast. The weather sensitive component is decomposed into (1) residential demand and (2) commercial and other demand. For each category of demand a mean and variance is computed, with residential weather sensitive demand possessing the dominating variance. The individual categories are then combined, making it possible to associate probabilities with annual forecasts of consumer total peak demand.

Forecasting Peaks by the Weather, Donald Gillus, Electric Light & Power, Aug. 15, 1957, pp. 70–76.

Article discussing daily load forecasting in southern Ontario. Describes application of weekly forecasts to long-range forecasting.

SYSTEM FORECASTING PRACTICES—GENERAL

Electric System Load Forecasting, System Planning Subcommittee, Edison Electric Institute, March 1957, Publication No. 57-3.

This report is confined largely to the estimating of Kilowatts and Kilowatthours, which are basic (kvar requirements and supply are also considered and can be similarly estimated)—Outlined are methods and factors involved in making electric utility load forecasts. Based on a survey of 34 utilities ranging in size and other information available,

an attempt was made to reflect a review of current thinking of the industry on principal practices and procedures bearing on load forecasting and to review some specific forecasting methods used by industry today to improve the accuracy of load estimates.

Forecasting the Demand for Electricity, R. G. Hooke, AIEE Power Apparatus & Systems, October 1955.

The method described consists of forecasting sales by classes of service for a time interval of either a year or a month, 10 years in the future. A secular trend is then drawn from present data to the forecast condition 10 years hence. Next, an estimate is made of expected deviations from trend, especially in the near-term years. By summing up the estimates of sales and adding losses and certain other adjustments, a forecast of total output is made. Expected peak demands, which are the ultimate objective of forecasts used in system planning, are obtained by a process of correlating peaks with consumption and system output.

Load Estimating Manual, Bonneville Power Administration, U.S. Department of the Interior, Bonneville Power Administration, 1965.

This manual describes a method of estimating future loads by forecasting the growth of all the component parts. The probable number of customers to be served in future years and the average use of electricity by each class are estimated and used to determine the utility's total load. Affects of history, population, employment, agriculture, forestry, industries, transportation and other economic factors are presented in the manual.

Load Research Can Help Improve Service, C. R. Harvey, Transmission and Distribution, June 1968, pp. 99–101.

Describes the use of recorders in customers' homes to gather data on residential load characteristics. Study provided improved bases on which forecasts could be made.

Electrical Utility Load Forecasting, W. Wallace Godard, The Cleveland Electric Illuminating Co., Cleveland, Ohio, AIEE Power Apparatus & Systems, February 1956; pp. 1428–1440.

The author emphasizes the application of economic factors in predicting the various components of electric utility loads. Class loads are estimated separately and then combined on a coincident basis. The number of customers and the KWH per customer use determine the total energy sales for residential and general commercial classes. Predictions of load factors and sales are used to forecast large commercial and industrial demands. The probable maximum demands of large customers, street and traffic lighting, and railroads and railways are predicted by company representatives, based on their knowledge of individual situations and consultations with the customers.

Forecast Loads Four Ways, Summary of methods presented at PEA System Planning Committee Meeting, Electrical World, June 4, 1962; p. 41.

The 4 methods discussed are as follows: (1) Information on land use, population, and basic industries is developed in the form of mathematical equations in order to obtain a forecast. (2) Actual energy consumption is related to actual demands by factors developed through a computer program. (3) Monitoring of circuits with recording meters, determining monthly peaks, projecting trends, and use of judgment are components used in another method of forecasting loads; and (4) Have a statistical department prepare a forecast of the future for stations, circuits, and system loads.

Short Range Peak Load Prediction Method Aids System Planning, W. L. Carey, Portland General Electric Co., Electric Light & Power, Feb. 15, 1961.

This article presents the method by which Portland General Electric Company predicts its system peak load one or two years into the future. A regression analysis between weekday peak loads and associated mean daily temperatures for the month of January (the usual peak month) for the interval 1947–1958 extracts the irregular and erratic growth elements which, over an extended period of time, balance out to zero. Temperature variation, which also balances out to zero, is eliminated by deriving the most likely peak load temperature, leaving load growth as the sole variable having a cumulative effect on peak demand. The annual growth rate for peak demand is then derived by a least squares fit of the compound interest curve to the residual peak demands. Short-range forecasting is accomplished by applying the compound interest formula using the trend peak load of the most recent year and the computed growth rate, modified by an empirically developed probability factor reflecting erratic, irregular, and temperature deviations, depending upon the degree of risk desired. In this manner, probabilities may be associated with short run peak demand forecasts without identifying any of the variables involved except annual load growth.

Load Forecasting on the TVA System (Part I) Substation Loads, W. R. New, AIEE Transactions-Power Apparatus & Systems, June 1962, pp. 101–105.

Efficient planning and design of the transmission system depends upon reasonably accurate forecasts of the loads it will serve. Substation load forecasts are prepared by the Tennessee Valley Authority (TVA) 15 years in advance. For the first 5 years, preliminary forecasts are prepared by months using time series analysis, carefully collected information, and judgment. Loads for another 10 years are extended largely on the basis of judgment. These preliminary forecasts are subjected to three critical reviews resulting in necessary modifications. The sum of adjacent substation loads is compared with larger area forecasts.

Load Forecasting on the TVA System—Part II, W. R. New, Tennessee Valley Authority, Chattanooga, Tenn., AIEE Conference Paper, No. CP 62–1111, June 1962.

The author discusses the forecasting of power use by commercial and industrial consumers on the TVA system. Loads are analyzed by size and the forecasting process is presented in two parts. One part involves the preparation of preliminary forecasts and the other, a series of critical reviews. Major steps in the forecasting process and a few of the many analytical tools are presented. The author points out that there is no substitute for the knowledge of the forecaster. His awareness of the region and its recent developments are the basis for the use of certain analytical tools.

Load Forecasting on the TVA System—Part III, W. R. New, Tennessee Valley Authority, Chattanooga, Tenn., IEEE Conference Paper, No. CP 63–222, January 1963.

This paper presents the various techniques used in forecasting residential energy use in the TVA service area. Methods for forecasting the number of customers, the average energy use per customer, and the total amount of energy consumed are discussed in the paper. Research findings pertaining to historical growth in energy use are used in the determination of future growth. It is noted that TVA's residential load accounts for approximately 50 percent of the total system peak. Its strong seasonal pattern

points up the importance of this class in determining the time of the system peak.

Load Forecasting on the TVA System—Part IV, W. R. New, Tennessee Valley Authority, Chattanooga, Tenn., IEEE Conference Paper, No. CP 63–955, June 1963.

Problems related to total system load forecasting are discussed in this paper. These include the importance of basic assumptions and the probabilities of deviations from the estimated load. Two assumptions discussed are the affects of weather and economic conditions. A method of combining the various class projections to obtain system peak forecasts is described including projections of the affect of losses and diversity on system load. The paper suggests that forecasting in detail increases the reliability of the forecast, because changes in trends are more likely to be anticipated. When decisions are to be made about the future, it is far better to make them based on a carefully prepared forecast.

The Disadvantages of Utility Control of Components of the Consumer's Load in Order to Reduce Peaks, William R. New, Tennessee Valley Authority, IEEE Transactions, Vol. IGA–4, No. 5, September–October 1968.

Control of water heating, electric heating and air conditioning loads to reduce peaks has several disadvantages that outweigh the advantages on most power systems today-Consumers will not use electricity to the maximum advantage if they feel that power to any appliance is not continuously available. The economics of the expenditure for controls are questionable. Load patterns change, making it difficult, if not impossible, to find a place in the daily load curve to fit loads that are interrupted. Control of water and space heating loads is becoming the accepted practice in Europe; however, there is greater incentive in Europe because often the load in off-peak hours is only one-third the magnitude of the peak.

Function of Land Use Surveys in Power System Planning, E. L. Kanouse and J. W. Reinhard, Proceedings of the American Power Conference, 1955; pp. 560–569.

Land Use Data Improve Load Forecasts, Americo Lazzari, Electrical World, June 18, 1962, pp. 30–40.

Computer Speeds Accurate Load Forecasts at APS (Arizona Public Service), Lazzari, Hyland, Tickle, Electric Light & Power, February 1965, pp. 31–35.

Explain utilization of land-use surveys. Predictions of where and to what extent service requirements will grow in the future.

APPENDIX D

REPRESENTATIVE LIST OF SOURCES FOR FORECASTS OF ECONOMIC ACTIVITY, POPULATION AND INDUSTRIAL GROWTH AND DETAILED HISTORICAL STATISTICS

The Committee has found the forecasts and historical data obtained from the sources listed in this Appendix to be useful in analyzing historical utility growth and in preparing system forecasts. There are many other regional and national sources which are equally as useful; their omission from this list does not constitute a value judgment by the Committee. The individual forecaster should have ready access to such documents and, in addition, may develop his own library of historical statistics and forecasts for cities, counties and other areas within his service territory.

Data requirements and adjustment are discussed in Chapter IV of this report.

KEY

Coverage categories:

U.S.	Data for United States as a whole.
State	Data for States.
County	Data for individual counties.
SMSA	Data for Standard Metropolitan Statistical Areas as defined by the Bureau of the Census.
City	Data for individual cities usually limited to cities having in excess of a specified population.
SIC	Standard Industrial Classification Codes designating specific industries and industry groupings.

Frequency of distribution:

D	Daily
W	Weekly
M	Monthly
A	Annually
O	Occasionally, irregular schedule
V	Varies, depending upon originator
Q	Quarterly
3	Every 3 years
5	Every 5 years
10	Every 10 years

Order from:

In those instances where the document should be ordered from a location other than the originator, the following codes apply:

1	Any regional office
2	Superintendent of Documents U.S. Government Printing Office Washington, D.C. 20402
3	National Weather Records Center Asheville, North Carolina

Industrial and Economic Trends and Forecasts

Title	Contents	Coverage: U.S.	State	County	SMSA	City	SIC	Frequency	Originator	Order from
Annual Business Outlook, Studies in Business Economics.	Comprehensive short range forecasts.	X						A	National Industrial Conference Board, 845 Third Ave., New York, N.Y. 10022.	....
Annual National Economic Forecast.	Short range forecast.	X						A	Prudential Insurance Company of America.	1
(Annual forecasts)	Business outlook forecasts.	X						A	American Statistical Association, 810 18th St. N.W., Washington, D.C. 20006	....
(Annual forecasts)	Business outlook forecasts.	X						A	National Association of Business Economists, Post Office Box 28038, Washington, D.C. 20005.	....
(Annual forecasts)	National and regional business outlook forecasts.	X	X					A	Major national banks	....
Barron's, The National Business and Financial Weekly (periodical).	Current trends and outlook.	X						W	Dow Jones, Inc., 30 Broad St., New York, N.Y. 10004.	....
Business Week (periodical).	Current trends and outlook.	X						W	McGraw-Hill, Inc., 330 West 42d St., New York, N.Y. 10036.	....
Dun's Review (periodical).	Current trends and outlook.	X						M	Dun's Review, Post Office Box 3088, Grand Central Station, New York, N.Y. 10017.	....
Economic Report of the President.	Includes annual report of the Council of Economic Advisors, short-range forecasts, and summarization of economic policy at the Federal Government level.	X						A	Council of Economic Advisors.	2
Electrical World (periodical).	Basic reference periodical for electric utility industry. Semi-annual reports on results of surveys of business men's capital expenditure intentions; forecasts of population, economy and growth of electric utility industry.	X						W	McGraw-Hill, Inc. 330 West 42d St., New York, N.Y. 10036.	....
Forbes (periodical)	Current trends and outlook.	X						M	Forbes, 60 Fifth Ave., New York, N.Y. 10011.	....
Fortune (periodical)	Current events and short-range forecasts for economy and industries.	X						M	Time, Inc., 540 N. Michigan Ave., Chicago, Ill.	....
Industrial Outlook for the United States.	1-year forecasts of activity by industry.	X					X	A	Business and Defense Services Administration, U.S. Department of Commerce.	2
National and Regional Forecasts.	5- and 10-year economic projections.	X	X					O	National Planning Association, Center for Economic Projections, 1606 New Hampshire Ave., N.W., Washington, D.C.	....
Newsweek (periodical).	Current events with short-range forecasting implications. Reports results of University of Michigan consumer surveys.	X						W	Newsweek, 350 Dennison Ave., Dayton, Ohio 45401.	....

Industrial and Economic Trends and Forecasts—Continued

Title	Contents	Coverage U.S.	State	County	SMSA	City	SIC	Frequency	Originator	Order from
Population Projections (Current Population Reports, Series P–25).	Forecasts of households, families, population to 1985.	X						O	Bureau of the Census, U.S. Department of Commerce.	
Predicasts	Compendium of short- and long-range forecasts of population, economy and industrial activity.	X						O	Predicasts, Inc., 10550 Park Lane, University Circle, Cleveland, Ohio, 44106.	
U.S. News and World Report (periodical).	Current trends and outlook.	X						W	U.S. News and World Report, 2300 N St. N.W., Washington, D.C. 20037.	
Wall Street Journal (periodical).	Current trends and outlook.	X						D	Dow Jones, Inc., 30 Broad St., New York, N.Y., 10004.	
	Annual business forecast for nation and California.	X						A	University of California at Los Angeles Graduate School of Business Administration, Los Angeles, Calif.	
	Forecasts of industry outputs, investments, employment and consumer purchases by categories.	X	X	X			X	O	University of Maryland, Bureau of Business and Economic Research, College Park, Md.	
	Annual econometric forecast of the national economy.	X						A	University of Michigan, Department of Economics, Ann Arbor, Mich.	
	Econometric forecasts of the national economy by quarter.	X						A	University of Pennsylvania, Wharton School of Business, Philadelphia, Pa.	

Energy Industries Statistics

Title	Contents	Coverage U.S.	State	County	SMSA	City	SIC	Frequency	Originator	Order from
Historical Statistics of the Electric Utility Industry and Statistical Yearbook of the Electric Utility Industry.	Data on generation, capacity, cate gories of sales, prices, and other historical statistics.	X	X					A	Edison Electric Institute, 750 Third Ave., New York, N.Y. 10017.	
Petroleum Facts and Figures.	Statistics on all phases of petroleum industry, including pricing and transportation.	X	X					A	American Petroleum Institute, 1271 Avenue of the Americas, New York, N.Y. 10020.	
Gas Facts	Detailed coverage of physical and financial operations.	X	X					A	American Gas Association, Bureau of Statistics, 605 Third Ave., New York, N.Y. 10016.	
Statistics of Electric Utilities in the United States Privately-Owned.	Annual sales, financial, production and operating statistics for individual systems.	X						A	Federal Power Commission.	2
Statistics of Electric Utilities in the United States Publicly-Owned	Annual sales, financial, production and operating statistics for individual systems.	X						A	Federal Power Commission.	2

Employment and Earnings Statistics

Title	Contents	Coverage						Frequency	Originator	Order from
		U.S.	State	County	SMSA	City	SIC			
Employment and earnings statistics for states and areas (1939–1965).	Number of employees, average weekly earnings, average hours worked, average hourly earnings.		X		X	X	X	O	Bureau of Labor Statistics, U.S. Department of Labor.	2
Various labor reports for states.	Current employment, hours, earnings, and turnover data for states and small areas.		X	X			X	M	State Department or Labor of Employment —each state.	....
Employment, earnings and monthly report on the labor force.	National statistics on employment, unemployment, labor force, hours worked, earnings, manhour indexes and turnover rates.	X	X				X	M	Bureau of Labor Statistics, U.S. Department of Labor.	2

Business and Economic Statistics

Title	Contents	Coverage						Frequency	Originator	Order from
		U.S.	State	County	SMSA	City	SIC			
Census of Manufactures.	Wide variety of data on manufacturing firms, including size employees, production, energy consumed, and payroll.	X	X	X	X	X	X	5	Bureau of the Census, U.S. Department of Commerce.	2
Current Industrial Reports.	Current activity by industry.	X					X	M	Bureau of the Census, U.S. Department of Commerce.	2
County Business Patterns.	Number of employees, payroll, and number of business firms, by industry.	X	X	X			X	3	Bureau of the Census, U.S. Department of Commerce.	2
Survey of Current Business.	GNP sectors, personal income, plant and equipment expenditures, industrial production, business sales and inventories, wholesale and consumer prices, construction and real estate.	X					X	M	Office of Business Economics, U.S. Department of Commerce.	2
Federal Reserve Bulletin.	Monthly indexes of industrial production and prices as well as other economic and monetary data.	X					X	M	Division of Administrative Services Board of Governors, Federal Reserve System, Washington, D.C. 20551.	....
Economic Indicators..	Monthly and quarterly trends in GNP, labor force, unemployment, industrial production, new construction, retail sales, prices, and financial indicators.	X						....M	Council of Economic Advisors.	2

Business and Economic Statistics—Continued

Title	Contents	Coverage U.S.	State	County	SMSA	City	SIC	Frequency	Originator	Order from
Business Conditions Digest.	Compendium of data from many sources organized to show leading, coincident, and lagging indicators of cyclical economic activity. Anticipated expenditures by businessmen and consumers are included, along with GNP components.	X						M	Bureau of the Census, U.S. Department of Commerce.	2
Various reports and newsletters.	Current business conditions and trends for Federal Reserve Districts.	X	X					M	Economic Research Department, Federal Reserve Banks (New York, Richmond, St. Louis, etc.).	....
Various reports and newsletters.	Current business conditions and trends for specific industries and small areas.	X	X	X				V	Economic Research Department, major banks, universities, utility companies, and State agencies.	....

Marketing and Product Sales Statistics

Title	Contents	Coverage U.S.	State	County	SMSA	City	SIC	Frequency	Originator	Order from
Merchandising Week.	Statistics on sales of TV and other key appliances by approximately 11,000 retailers across the United States who report their monthly unit volumes to utility companies.							W	Merchandising Week, 165 West 45th St., New York, N.Y., 10036.	....
Marketing Information Guide.	Compendium of publications of either specific or general interest to forecasters. Emphasis is on statistics and major industry segments.	X					X	M	Office of Marketing Services. U.S. Department of Commerce.	2
Industrial Marketing Market Data and Directory Number.	Wide variety of current statistics and trend information for major service and product markets. Aimed at industrial marketers.	X					X	A	Advertising Publications, 200 East Illinois St., Chicago, Ill.	....
Consumer Buying Indicators (Current population report series P–65).	Results of quarterly surveys of recent purchase of automobiles, selected household durables, with projected buying intentions for 12 month period.	X						O	Bureau of the Census, Department of Commerce.	2

Population and Housing Statistics

Title	Contents	Coverage U.S.	State	County	SMSA	City	SIC	Frequency	Originator	Order from
Census of Population	Detailed data from decennial census. (1950, 1960, etc.). Most authoritative source relating to number, location, and characteristics of U.S. population. Available on cards, tape, and hard copy.	X	X	X	X	X		10	Bureau of the Census, U.S. Department of Commerce.	2
Current Population Reports.	Results of current population surveys. Topics include characteristics, counts, consumer income and employment estimates based upon random sampling.	X						0	Bureau of the Census, U.S. Department of Commerce.	2
Census of Housing	Detailed data on housing and appliances from decennial census.	X	X	X	X			10	Bureau of the Census, U.S. Department of Commerce.	
Current Housing Reports.	Vacancy rates, vacancy characteristics and TV set ownership.	X	X					Q	Bureau of the Census, U.S. Department of Commerce	2
Current Construction Reports.	Building permits, starts, sales, construction activity in series of monthly reports.	X						M	Bureau of the Census, U.S. Department of Commerce.	2
Statistical Abstracts	Standard summary of statistics on population, earnings, labor force, prices, construction, industrial production and trade. Guide to other sources.	X	X	X				A	Bureau of the Census, U.S. Department of Commerce.	
City and County Data Book.	Supplements Statistical Abstracts. Published at irregular intervals. Provides data for counties, cities, and other small areas.	X	X	X	X	X		V	Bureau of the Census, U.S. Department of Commerce.	2
Sales Management Survey of Buying Power.	Population, households, income, retail sales, number of farms. Gives more current information on small areas than is available from Census.	X	X	X	X	X		A	Bill Brothers, Publishing Corp., 630 Third Ave., New York, N.Y.	

Weather Data

Title	Contents	Coverage U.S.	State	County	SMSA	City	SIC	Frequency	Originator	Order from
Detailed weather data.	Temperature, humidity, and other data for reporting stations throughout the country. Data available hard copy, microfilm, and tape.						X	On request.	Environmental Science Services Administration, U.S. Department of Commerce.	3

APPENDIX E

SAMPLE FORMS REQUEST FOR INFORMATION ON FORECASTING METHODS AND RESULTS

The letter and forms in this Appendix were submitted to the Chairmen of the six Regional Advisory Committees soliciting information on the current forecasting practices of a representative number of utility systems. The results of the responses from 30 systems are discussed in Chapter V of the report.

FEDERAL POWER COMMISSION,
Washington, D.C., September 5, 1968.

Memorandum To: Chairmen, Regional Advisory Committees.
From: Chief, Bureau of Power.
Subject: Request for Information for Advisory Committee on Load Forecasting Methodology.

This memorandum transmits a questionnaire prepared by the Commission's Advisory Committee on Load Forecasting Methodology. The information sought pertains to current practices of utilities in load forecasting.

The Committee suggests that the questionnaire be distributed to a representative number of utilities in each region, perhaps three or four in number, one of which might be other than a private utility. In summarizing the data in the Committee's report, no identification of cooperating utilities will be included other than the general geographic location and some of the principal system characteristics. It should be emphasized that no special studies or analyses are being requested to provide the numerical data itemized in the questionnaire; such data should be provided only if readily available.

It would be appreciated if each Regional Chairman would distribute the questionnaires to utilities of his selection, including any known to him who have developed special programs of analysis. It is requested that the questionnaires be completed by October 15, if possible, and returned directly to the Committee Chairman, Mr. W. R. Brownlee, President, Southern Services, Inc., 600 North Eighteenth Street, Birmingham, Alabama 35202.

The studies of the Advisory Committee on Load Forecasting Methodology should prove to be useful to the industry. Your assistance and the cooperation of assisting utilities will be very much appreciated.

F. STEWART BROWN.

Attachment.

REQUEST FOR INFORMATION BY THE ADVISORY COMMITTEE ON LOAD FORECASTING METHODOLOGY

The Committee is desirous of assembling information that is readily available concerning the practices of a representative number of utilities in the United States in the forecasting of loads.

New techniques or techniques that have been especially successful are of particular interest. Forms are provided for completing Sections B1 and B2 including an example of a partially completed form for Section B2. Any member of the Load

Forecasting Methodology Committee may be contacted in the event questions arise concerning completion of the questionnaire. A list of those members is attached.

The information desired is as follows:

A. Current Forecasting Methods in Use

Describe the present methods used for forecasting energy and demand[1] for each of the following:

(a) Short Term—hour to hour, day to day, week to week, forthcoming seasonal peak, etc.

(b) Intermediate Term—4 to 6 years.

(c) Long Term—10 to 30 years.

In describing these methods include, for example, procedures used in estimating maximum weather conditions and their effects on the load projection, and procedures used in keeping abreast of air-conditioning and heating installations, industrial and commercial developments and trends in population.

B. Forecasting Accuracy

1. If readily available, state the error (forecast error as a percent of actual demand or energy) for the various categories of forecast in Part A for 1967 as specified below. The comparison of actual results should be made with the forecasts:

(a) Without any adjustments

(b) With adjustments, if desired, for the actual climatic and other conditions experienced. (Please explain nature of adjustments made.)

2. Show the percentage error for each of the years 1958 through 1967 using Forms I and II attached. (Note sample Form I also attached.) Indicate any change in the method(s) of forecasting that may have been adopted during the period 1958–1967, inclusive and why such change was adopted.

3. Show the percentage error in forecasts of monthly energy (Form III) and demand (Form IV) for 1967 by months. In addition, if accuracy comparisons for other short range demand or energy forecasts, such as week to week, or day to day, can be provided conveniently, they would be useful to the Committee.

4. Indicate the range of accuracy that you have experienced in the long-range forecast of annual peak and annual energy (10–30 years). Please give examples.

C. Set Forth a Few of the Characteristics of the Reporting System Including:

1. Average 1967 load density—kwh/sq. mi.
2. Metropolitan, or a system made up of smaller cities (less than 1,000,000 population) and rural territory.
3. The largest single customer demand in percent of total system demand.
4. Approximate makeup of 1967 energy—residential, commercial, industrial, and other.
5. Ratio of 1967 summer peak demand to the following winter peak demand.
6. Approximate size of system.

D. Are interruptible loads considered as part of the total forecast loads?

E. Please describe the extent to which your system coordinates its load forecasts with those of other systems such as affiliated systems in a holding company group, associated systems in a power pool or other coordinating organization, or other neighboring systems. Describe the manner in which such forecasts are coordinated, and any problems experienced in efforts to coordinate load forecasts.

Attachments.

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[1] The integrated kwh for a sixty-minute time period is most commonly used. If any other demand period is used, please so indicate.

FORM I

Form for Completing Section B2 of the Load Forecasting Methodology Questionnaire Quantity, Annual Peak Hour Demand

[Forecast error—percent of actual]

Year forecast was made	1959		1960		1961		1962		1963		1964		1965		1966		1967	
	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted
1958																		
1959																		
1960																		
1961																		
1962																		
1963																		
1964																		
1965																		
1966																		
1967																		

FORM I

Form for Completing Section B2 of the Load Forecasting Methodology Questionnaire Quantity, Annual Peak Hour Demand

[Forecast error—percent of actual]

Year forecast was made	1959		1960		1961		1962		1963		1964		1965		1966		1967	
	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted
1958	−1.0	+1.0	−2.0	−1.0	−3.0	−1.0												
1959			−1.0	−0.	−2.0	−1.0												
1960					−2.0	−1.0												
1961																		
1962																		
1963																		
1964																		
1965																		
1966																		
1967																		

FORM II

Form for Completing Section B2 of the Load Forecasting Methodology Questionnaire Quantity, Annual Energy

[Forecast error—percent of actual]

Year forecast was made	1959		1960		1961		1962		1963		1964		1965		1966		1967	
	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted
1958																		
1959																		
1960																		
1961																		
1962																		
1963																		
1964																		
1965																		
1966																		
1967																		

FORM III

Form for Completing Section B3 of the Load Forecasting Methodology Questionnaire

[Forecast for 1967. Error as percent of actual. Quantity—Monthly Energy]

	Date forecast made for 1967		
	1966	1965	1964
Jan.—Adjusted			
Unadjusted			
Feb.—Adjusted			
Unadjusted			
Mar.—Adjusted			
Unadjusted			
Apr.—Adjusted			
Unadjusted			
May—Adjusted			
Unadjusted			
June—Adjusted			
Unajusted			
July—Adjusted			
Unadjusted			
Aug.—Adjusted			
Unadjusted			
Sept.—Adjusted			
Unadjusted			
Oct.—Adjusted			
Unadjusted			
Nov.—Adjusted			
Unadjusted			
Dec.—Adjusted			
Unadjusted			

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